94th Congress } COMMITTEE PRINT
2d Session }

ESTIMATES OF THE ECONOMIC COST OF PRODUCING CRUDE OIL

PRINTED AT THE REQUEST OF

HENRY M. JACKSON, Chairman

COMMITTEE ON INTERIOR AND INSULAR AFFAIRS

UNITED STATES SENATE

PURSUANT TO

S. Res. 45

A NATIONAL FUELS AND ENERGY POLICY STUDY

Serial No. 94–27 (92–117)

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Committee on Interior and Insular Affairs

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SENATE RESOLUTION 45

NATIONAL FUELS AND ENERGY POLICY STUDY

This publication is printed for the use of Senators participating in the National Fuels and Energy Policy Study, authorized by Senate Resolution 45 of the 92d Congress.

S. Res. 45, introduced by Senators Jennings Randolph and Henry M. Jackson, was amended and agreed to by the Senate on May 3, 1971. The resolution authorized the Senate Committee on Interior and Insular Affairs and ex officio members of the Committees on Commerce and Public Works and the Joint Committee on Atomic Energy to make a comprehensive study of programs and policies required to meet national energy needs.

Subsequently, the Senate approved the addition of ex officio members from the Committees on Aeronautical and Space Sciences, on Finance, on Foreign Relations, on Government Operations, and on Labor and Public Welfare.

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MEMORANDUM OF THE CHAIRMAN

To Members and Ex Officio Members of the National Fuels and Energy Policy Study (S. Res. 45, 92d Congress), Committee on Interior and Insular Affairs:

During 1974 and 1975 a major question before the Congress concerned the price which should be charged the U.S. economy for domestically-produced crude oil. As a leader in the production of crude oil in the world, the United States has maintained a series of policies with respect to domestic oil prices over the years. The fourfold increase in the world oil prices between 1973 and 1975 triggered a renewed and often acrimonious debate on oil price policy in the United States.

One of the important features of this debate has been the issue of the actual cost to the oil producers of producing oil from existing reserves and the cost of finding, developing and producing oil from new sources of supply.

To clarify this question I therefore asked the staff of the Senate Committee on Interior and Insular Affairs to work with appropriate personnel in the Congressional Research Service to assemble the most authoritative recent studies and analyses of these costs.

The compilation of documents and views which follows is the result of the efforts of the committee's economic consultant, Professor Arlon R. Tussing of the University of Alaska, and Dr. Benjamin S. Cooper of the committee's professional staff, with the assistance of Henry Canaday of the Economics Division of the Congressional Research Service. Because the issues discussed deserve a wider audience and the analysis presented clearly demonstrates the need for further work on this important subject, I have asked that this material be made available in the form of a Committee Print.

HENRY M. JACKSON, *Chairman.*

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INTRODUCTION

Estimates of the Economic Cost of Producing Crude Oil

1. Crude Oil Price History Since 1973

Over the course of a few months in 1973 and 1974, the average price of crude oil imported into the United States increased threefold—from about $3.60 per barrel to more than $10—as a result of concerted action by the Organization of Petroleum Exporting Countries (OPEC). Price increases continued throughout the following year; according to the Federal Energy Administration (FEA) crude oil import prices averaged $12.52 per barrel in 1974.

Because the discovery and development of additional crude oil supplies would take several years at best, there was no way in which refiners in the United States could quickly replace these expensive imports with crude oil from domestic sources. American consumers had no choice but to pay the higher OPEC price or go without essential petroleum products for transportation, home heating and industry.

In the absence of price controls, moreover, the prices of domestic crude oil would have been quickly bid up to the level of the corresponding grades and qualities of OPEC oil (with regional adjustments for transportation costs). Higher petroleum prices would—and did—tend also to pull up the prices for other fuels which were not subject to price controls, such as coal and intrastate natural gas supplies.

In an attempt to mitigate the impact on American consumers and industry of a huge and sudden increase in the price of all fuels the Cost of Living Council (COLC) under the authority of the Economic Stabilization Act extended the crude oil price controls established in summer 1973. This program froze prices of all "old" crude oil—oil from wells already producing in 1972—at May 15, 1973 prices (an average of approximately $3.90) plus 35 cents. "New" oil—oil from new wells and oil from old wells in excess of their 1972 production—was left free to rise to the OPEC price. The COLC program also "released" from controls a barrel of old oil from each producing property for every barrel of new oil produced from the same property. In November the Trans-Alaska Pipeline Act (P.L. 93–153) was enacted. In this legislation, the Congress specifically exempted from controls oil from "stripper wells"—those wells producing less than 10 barrels per day.

The price of new oil in September 1973, was approximately $5.00 per barrel and exceeded the cost of imports landed in that month by $0.25 to $0.35 per barrel. On October 16, 1973, six Persian Gulf members of OPEC announced increases in the posted price of crude oil (FOB the Persian Gulf) from $3.01 per barrel to $5.12 per barrel. One

day later, in Kuwait, the Arab embargo was announced. The price of domestic new oil began to rise precipitously.

On November 27, 1973, President Nixon signed the Emergency Petroleum Allocation Act of 1973 (P.L. 93–159) committing the President to promulgate a regulation providing for the equitable allocation of petroleum at equitable prices.

By the end of November 1973, 75 percent of domestic oil was selling at an average of $4.25 per barrel and 25 percent was classified as new oil, selling for $6.17 per barrel. On December 18, 1973, the COLC, in an attempt to minimize the disparity in refiner crude costs under the two-tier system, announced an increase in the ceiling price permitted for old domestic crude oil of $1.00 per barrel, from approximately $4.25 to approximately $5.25 per barrel. The FEA has continued to report $5.25 per barrel as the average old oil price.

On December 23, 1973, OPEC announced that the world price of crude oil would double at the beginng of the year. Saudi Arabia raised the posted price of its "marker" crude oil from $5.12 to $11.65 per barrel, effective January 1, 1974.

Responsibility for the administration of the petroleum price control regulation was transferred from the Cost of Living Council to the Federal Energy Office (FEO) on December 26, 1973. On January 15, 1974, the FEO issued the basic price control and allocation regulation for crude oil and refined petroleum products. This price control regulation reflected regulations originally administered by the COLC and permitted domestic "new" oil prices to float to reflect the world price level established by OPEC. In February the landed price of imported crude oil—approximately $12.50 per barrel—passed the domestic new oil price for that month of approximately $9.90 per barrel.

On March 6, 1974 President Nixon vetoed S. 2589, the Energy Emergency Act, which provided for a rollback to approximately $7.00 per barrel of the price for domestic "new" oil not subject to price controls under the Allocation Act regulation. At that time, "new" oil in the U.S. was selling for nearly $10 per barrel.

On April 30, 1974, the statutory authority for the COLC program contained in the Economic Stabilization Act of 1970 expired, and the Emergency Petroleum Allocation Act became the sole source of Federal price control authority for petroleum. On June 27, 1974, the President transferred all functions of the FEO to the Federal Energy Administration, created by the Federal Energy Administration Act of 1974 (P.L. 93–275, May 7, 1975). By midyear, domestic new oil prices were on a plateau at just under $10 per barrel, over $2.50 per barrel below the reported landed price of imported oil.

During the fall, the price of new oil began to rise again, reaching $11.28 per barrel in January of 1975.

The Senate passed, on November 21, 1974, and the President signed, on December 5, 1974, Public Law 93–511, extending the Emergency Petroleum Allocation Act of 1973 until August 31, 1975. On September 9, 1975, President Ford's veto of S. 1849, which would have extended the Allocation Act price control authority, beyond 1975, was sustained in the Senate. All Federal authority to control oil prices lapsed, pending resolution of the continuing disagreement between the President and Congressional opponents of the Administration's proposals on oil price policy.

This controversy was resolved by the President's decision to sign, on December 22, 1975, S. 622, the Energy Policy and Conservation Act, extending crude oil price controls for 40 months. At the same time, as part of the agreement with Congressional Democrats over the structure of S. 622, the President removed the $2.00 per barrel supplementary fee on crude oil imports which had been imposed during 1975. This fee had raised the cost of imported oil to the U.S. economy to nearly $15.00 per barrel by the end of 1975. In addition domestic upper tier (new, released and stripper) oil prices—free to reflect changes in the cost of imported oil—rose from $11.28 per barrel in January 1975, to $12.95 per barrel in December 1975. Table I presents crude oil prices paid by U. S. refiners from 1973 through 1975 and estimates of the prices which can be expected to prevail under provisions of the Energy Policy and Conservation Act over the life of the price-control program enacted in that legislation.

TABLE I.—U.S. CRUDE OIL PRICES

[Current U.S. dollars]

Year/quarter	Domestic: New	Domestic: Average [1]	Imports [2]	Composite including imports [3]
End of:				
1973:				
1st quarter		3.40	3.30	3.35
2d quarter		3.60	3.90	3.70
3d quarter	5.12	4.27	4.72	4.41
4th quarter	9.51	6.31	6.44	6.43
1974:				
1st quarter	9.88	7.05	12.73	8.68
2d quarter	9.95	7.20	13.06	9.45
3d quarter	10.10	7.18	12.53	9.13
4th quarter	11.08	7.39	12.82	9.28
1975:				
1st quarter	11.47	8.38	13.28	9.91
2d quarter	11.73	8.38	14.15	10.33
3d quarter	12.46	8.49	14.04	10.79
4th quarter	12.95	8.66	14.81	10.98
S. 622 [3]	11.28	7.66	13.00	9.70
1976:				
1st quarter	11.47	7.84	13.19	9.87
2d quarter	11.67	8.03	13.38	10.06
3d quarter	11.87	8.23	13.58	10.32
4th quarter	12.07	8.43	13.78	10.52
1977:				
1st quarter	12.28	8.63	13.98	10.72
2d quarter	12.48	8.84	14.19	10.98
3d quarter	12.70	9.09	14.40	11.21
4th quarter	12.91	9.38	14.61	11.47
1978:				
1st quarter	13.13	9.82	14.82	11.82
2d quarter	13.36	10.41	15.04	12.31
3d quarter	13.59	10.65	15.26	12.54
4th quarter	13.82	10.88	15.48	12.77
1st quarter 1979	14.05	11.13	15.71	13.05
April 1979	14.14	11.21	15.79	13.13

[1] Pricing policy adopted by Conference Committee on S. 622. The policy does not specify the rate of increase in new oil prices within the composite. This table assumes old oil prices frozen at $5.25 and a 7 percent annual increase in new oil prices. Import prices landed in the United States are assumed to escalate at 6 percent per year.

[2] Actual average prices as reported by the FEA for imported crude oil landed in the United States are listed through December, 1975. Data after 1975 assumed removal of the tariff of $2 per barrel on imported crude oil and a rise in its landed price of 6 percent per year over the 40-mo. life of the program.

[3] Actual average refiner acquisition costs as reported by the FEA are listed through December, 1975. After 1975 it is assumed that imported oil comprises 38 percent of the input of crude oil to domestic refineries, and that this percentage increases gradually to 42 percent at the end of the price control program embodied in S. 622 (P.L. 94–163).

2. The Two-Tier System: Its Rationale and Its Critics

For the second half of 1973 during the embargo, and throughout the post-embargo period domestic crude oil prices were regulated under a "two-tier" regime: old oil controlled at $5.25 per barrel, and new, re-

leased and stripper oil left free to be sold at market prices. The rationale for this two tier price system was as follows: production of old oil was the result of investments made by producers who expected to receive a price of $3 to $4 per barrel. The bulk of the costs for this production had already been incurred in the course of exploration and development; therefore, it was reasoned, radically higher prices for old oil were not necessary or useful as incentives to increased production and would only exacerbate inflation and the forces which were pushing the economy into a deep slump. On the other hand, it was regarded as desirable to provide the maximum encouragement to the discovery and development of new domestic oil. New domestic supply would reduce the need for imports, improving national security and reducing the outflow of foreign exchange, but there would be no loss to consumers even if the price of new domestic oil were equal to that of the imported oil it replaced. In other words, according to the COLC view (and later that of the Federal Energy Office and the Federal Energy Administration), it was not reasonable to hold the price of new domestic oil below the cost of imported oil if raising the price would bring forth greater production and thereby reduce the volume of imports required.

The $5.25 per barrel oil price, the exemption from price controls of new, released and stripper well oil, and the principle of a two tier system itself were—and still are—controversial. It is not surprising that the oil producers objected to the controls on old oil; they were later joined by the Administration and by some professional economists. Controls were criticized on several grounds, among them, (1) that they discouraged investment in well workovers and enhanced recovery projects, which could retard the decline in production from established oil fields; (2) that they deprived the oil industry of cash flow necessary to finance investment in production of new oil and gas and of substitute fuels; and, (3) that price controls on any part of domestic oil supply induced consumers to waste it, that is, to consume oil as if it were only worth $5.25 per barrel, despite the fact that every barrel consumed at that price had to be replaced with a barrel of imported oil which cost the United States at least twice as much.

On the other hand, consumer representatives, many Members of Congress and a different group of economists regarded even the $5.25 old oil price as creating windfall profits and an excessive burden on consumers. They argued that even this price far exceeded the actual historical cost of developing and producing the supplies in question. The COLC and subsequently the Federal Energy Office were severely criticized for their failure to provide any cost justification for the dollar increase in the old oil price implemented in December 1973.

The absence of controls on new, released and stripper well oil also came under attack. The price of imported oil, it was argued, was far in excess of the long term cost of significant additions to domestic supply. Many authorities (including for a time Secretary of the Treasury Simon) held that prices more than $7 or $8 per barrel would result in little additional domestic supply but would only create windfall profits and lead to a further bidding up of the prices for lease acreage, rig time, tubular goods and special oil field services. Allowing domestic producers to receive the OPEC price would thereby impart both a demand pull and a cost push to general inflation which was

already raging at double digit rates. Moreover, regardless of the specific price level for new oil that might be most appropriate for optimizing domestic supply, there was widespread concern in Congress and the nation that the lack of controls on a large part of domestic supply gave moral sanction to prices set by the OPEC cartel, and that OPEC's effective control over domestic oil prices represented a significant diminuation of our national autonomy.

The principle of a two tier system was itself criticized from various quarters on the grounds, (1) that the distinction in COLC and FEA regulations between new and old oil did not effectively separate those elements of new supply which were sensitive to price incentives from those which were not; (2) that the system created incentives to hold old oil off the market and to engage in various legal and illegal subterfuges in order to convert price-controlled old oil into exempt new or stripper well oil; and (3) that the two tier system required a costly and clumsy system of allocation and "entitlements" in order to equalize oil prices among different refiners and different sections of the country.

3. Methods of Estimating the Cost of New Crude Oil Supplies

Among all the issues of debate regarding oil pricing policy the most critical concerned the cost of significant additional supplies of domestic crude oil. If the United States is not to become increasingly dependent upon imported oil, prices for domestic oil—for new supplies at least—will have to cover the expected cost of necessary materials and labor, plus a competitive return for the capital committed to exploration and development. The actual prices of oil received by producers would also have to be sufficient to cover lease acquisition charges, royalties and production taxes, although narrowly speaking these latter are not part of the "economic cost" of crude oil, that is, of the cost of oil to the economy as a whole.

If this cost could somehow be measured accurately, prices arguably could be established for new oil which would provide just the right incentive for domestic exploration and development, without creating either a permanent oil shortage or excessive profits and an unnecessary upward push to the general price level. Accordingly, estimates of the economic cost of crude oil became important weapons in the battle over oil pricing policy. During the period beginning with the Arab embargo in October 1973 and ending with enactment in late 1975 of S. 622, the Energy Policy and Conservation Act (P.L. 94–163), one could choose crude oil cost estimates from reputable sources ranging from less than the old oil price to more than the prices of OPEC imports. The present Committee Print reproduces or summarizes several of the most important documents in the debate over pricing policy leading to the policy compromise embodied in S. 622.

The economic cost of crude oil is an inherently elusive value to measure or estimate, even for presently producing oil fields. It requires among other things, (1) correctly assigning to each past year's investment in exploration and development, the number of barrels that were—or have yet to be—produced in each subsequent year as a result of that investment, and (2) choosing an appropriate value for the "cost of capital", at which to discount future sales and operating costs. The first task requires considerable ingenuity in rearranging the investment and reserve statistics available from government

agencies and industry groups, and in projecting both production levels and operating costs into the future. The choice of a discount rate is a largely arbitrary judgment, which may researchers evade by presenting their results on the basis of several alternative discount rates ranging in some cases from as little as six percent per year to as much as twenty-two percent. In these two tasks there is sufficient latitude for individual judgment that different researchers can produce defensible cost estimates varying by a factor of two or more. Some indication of the degree of this latitude can be seen in the dialogue between Robert R. Nathan and his collaborators with the staff and consultants of the Senate Committee on Interior and Insular Affairs, regarding the procedures and assumptions used by the former in their historical estimates of the economic cost of crude oil.

At their best, historical methodolgies such as Nathan's for estimating crude oil costs provide only the average cost of crude oil from reserves discovered in a particular year, and only the average cost corresponding to the actual volume of reserves added in that year. This figure, even if it were itself indisputable, would be of limited value in determining the correct price for crude oil. The average cost of crude oil produced from investments made in a given year conceals the fact that economic cost of crude oil from different properties will range upward from a few cents per barrel to the highest value that any producer believes prices will reach during the economic life of his investment.

If one purpose of estimating the cost per barrel of discovering and developing new oil reserves in the recent past is to indicate the price we must offer producers to induce them to discover and develop new oil reserves, the figure we need is not the average cost of crude oil but its marginal cost, that is, the additional outlay necessary to increase production by one more barrel. We need this estimate, moreover, not for the amount of oil that actually was produced, but for the amount we believe ought to be produced. A production level of 12 million barrels per day will imply a substantially higher marginal cost (and a higher required price) than a level of 8 million barrels per day. Even in the 12 million barrel case, marginal costs and the necessary producer price will vary considerably depending upon whether the additional 4 million barrels is squeezed out of old discoveries by means of tertiary recovery projects, or are the result of finding big new fields in frontier areas of the Outer Continental Shelf and Alaska. It follows that economic cost of new oil may be profoundly affected by Federal and State leasing, transportation and environmental policy in the frontier areas.

4. Cost Studies in this Report

Of the cost studies presented in this report, three were completed in 1975, that of Robert R. Nathan and his associates LaRue, Moore and Schaefer, that of Butler, Miller and Lents and that of Standard Oil of Indiana. The first two estimate the average costs for oil from each year's discoveries over the whole productive life of those discoveries. Nathan's study produces an economic cost for 1974 discoveries of $12.73 per barrel; Butler, et al., arrive at a figure of $9.73 for 1973 discoveries. Both of these figures are average costs in current dollars for the reserve additions attributed to the respective year's discoveries.

The Standard of Indiana report is based upon a detailed engineering analysis of the company's own United States properties, and the

company's internal cost-estimation procedures. Accordingly, it is probably more "realistic" as a forecast of industry response to crude oil prices than the other studies, all of which use historical data. This company study does not give a single "cost" figure, but rather concludes that prices around $12 per barrel in 1975 prices represent a threshold above which the supply of liquid hydrocarbons becomes more responsive to prices. In this price range, the price elasticity of the supply of new reserves increases from about 0.7 to about 1.0, as prices begin to support discovery and development of reserves in deep offshore areas, remote parts of Alaska, and tertiary recovery from existing reserves.

The 1974 study of Davidson, Falk and Lee assumed that 1971 was an "equilibrium" year with respect to oil production and consumption, and that the price elasticity of supply was 1.6, that is, that each percentage increase in real prices for crude oil would result in a 1.6 percent increase in current production. The authors claim to find that an oil price of $5.36 per barrel would have sufficed to meet 1974's domestic oil demand, had producers not withheld production in anticipation of higher prices.

The 1973 report of the National Petroleum Council (NPC) estimated the average cost of all crude oil production in various future years on the basis of assumed drilling rates. success rates and the cost of drilling. According to this study, the average cost in 1980 of 10.4 million barrels per day (reflecting pessimistic discovery assumptions) would be $5.28 per barrel, and average cost of 15.5 million barrels per day (reflecting optimistic discovery assumptions) would be $6.69 per barrel, both in 1973 dollars.

The 1974 studies cited here by the Federal Energy Administration and the MIT group use the NPC estimates as a base, and adjust them for price by the use of estimates for the price elasticity of supply derived from other models. The MIT report, for example, using 1973 cost levels, implies that the volume of domestic production would largely be insensitive to prices higher than $7 to $9 per barrel. Higher prices would, on the other hand, be expected to have a profound effect on oil consumption as a result of both conservation and fuel substitution. As a result, the authors forecast that no imports at all would be needed in 1980 if the price of domestic crude oil were $11 to $13 in 1973 prices.

5. Crude Oil Price Policy Through 1979

It is apparent from the brief summary offered here and from the following table ("Summary of Oil Price Studies") that cost estimates from respectable authorities are available to support a wide variety of pricing policies. None of the studies cited here, however, is clearly inconsistent with the policy adopted by Congress in the Energy Policy and Conservation Act. That legislation and the regulations adopted by FEA in order to implement it provide for the continued control of old oil prices at about $5.25 per barrel and a ceiling on previously exempt crude oil prices of $11.28, with the average of all domestic crude oil prices increasing (in the absence of Congressional action to retard or accelerate them) at approximately 10 percent per year to reflect both inflation and the declining proportion of old oil in total domestic supply. Price controls on crude oil will, unless extended by further legislation, expire in 40 months.

This measure was essentially a compromise between the position of Congress which desired lower prices and a longer period for the

phasing out of price controls, and the Administration which initially advocated immediate decontrol. With adoption, the "economic cost of crude oil" does not seem to be the vital issue it was from 1973 to 1975. The debate continues at a lower pitch in government, industry and academic circles, however, and can be expected to emerge as a major public issue again if the Administration should propose major changes in the level or structure of prices under S. 622, and will certainly come into renewed prominence toward the end of the 40 month period when controls are now scheduled to lapse. Some of the studies reprinted or cited here will again be referred to, and will in some cases be updated, and other, more sophisticated estimates (we hope) will appear.

SUMMARY OF OIL PRICE STUDIES

Source and nature of estimate	Date of study	Date of cost levels assumed	Price/cost estimate	Supplies considered	Profitability standard used	Policy assumptions	Volume of production/demand	Relations between price and supply/demand methods and assumptions governing results
Nathan-LaRue, Moore & Schafer: Minimum economic price for crude reserves added by exploration and development during each of the years 1959 through 1974.	1975	1974	$12.73 ($13.84)	Excluding North Slope, crude reserves added in 1974.	15 percent discounted cash flow.	Historical Government actions toward development; continuance of depletion allowance.	Historical reserves added in 1974.	Reserve additions adjusted from American Petroleum Institute data, producible volume does not vary with price, demand not considered. Study estimates the price which, maintained over life of producing reserves, would have justified the actual exploration and development that took place during each of the cited years. Bonus, roaylty and all lease expenses included in cost calculations.
Do	1975	1970	$7.25 ($10.02)	Same, in 1970	do	do	Same, in 1970	Do.
Do	1975	1960	$3.40 ($6.05)	Same, in 1960	do	do	Same, in 1960	Do.
Standard of Indiana: Ultimate liquid hydrocarbon availability at various prices.	1975	1975	Supply becomes significantly more price responsive at almost $12.	U.S. liquid hydrocarbons, including synthetics at prices above $15.	Company's internal standards, which include debt-equity ratios as well as rates of returns.	Net stated	Ultimate reserves of liquid hydrocarbons.	Cost engineering analysis of Amoco's own properties, and company's exploration cost experience.
Do								
Butler, Miller & Lents: Cost of reserve additions during each specified year (includes all finding and production outlays, excludes profits or taxes).	1975	1973	$9.83 ($11.72)	U.S. petroleum and natural gas reserves.	No return on investment.	Historical policies, since profitability was not considered, no assumptions were made as to Federal tax treatment of earnings.	Reserves added in 1973.	Like LaRue, Moore, & Schafer, essentially matches estimate of reserves added during each year with expenditures on exploration and development. These capital expenditures, taken from Chase Manhattan pamphlet, include investment in oil and gas; expected income from gas reserves (selling at FPC interstate prices) is deducted from total investment to estimate the per barrel "cost" of oil finding. Reserve additions, taken from API include discoveries and extensions; exclude either each year's actual revisions or a factor reflecting anticipated revisons

SUMMARY OF OIL PRICE STUDIES—Continued

Source and nature of estimate	Date of study	Date of cost levels assumed	Price/cost estimate (1975 dollars)	Supplies considered	Profitability standard used	Policy assumptions	Volume of production/demand	Relations between price and supply/demand methods and assumptions governing results
								These procedures result in an investment figure substantially larger than, and a, reserve addition figure generally less than. those contained in LaRue, Moore & Schafer.
Do	1975	1970	$3.73 ($5.16)	U. S. petroleum and natural gas reserves.	No return on investment.	Historical polices since profitability was not considered, no assumptions were made as to Federal tax treatment of earnings.	Same, for 1970	
Do	1975	1966	$2.81 ($4.63)	do	do	do	Same, for 1966	
MIT—Projected price that would balance supply and demand at cited import levels: (Authors' conclusion)	1974	1973	$11 to $13 per barrel ($13 to $15.50)	All U.S. energy sources are forecast at various price levels and summed to total domestic production.	No explicit standard.	United States seeks partial or complete self-sufficiency by 1980; price controls on natural gas are maintained; surface mining permitted on Montana coal.	1980 U.S. petroleum consumption matches domestic supply, demand depressed below 1974 levels.	Several versions of energy equilbrium are presented with energy production forecast according to both an MIT model and an adjusted forecast of the National Petroleum Council (see NPC below). 1980 energy demand is also projected by the Hudson-Jorgenson model and by a judgemental forecast. Higher prices encourage reserve development but do not add appreciably to 1980 volume of production above $9 per barrel. Bulk of import savings thus trace to quite substantial demand cuts, as well as boosted coal output. Model's elasticity for total energy demand is about 0.15.
(Erickson-Spann Model results).	1974	1973	$7 per barrel ($8)	do	Model implies historical domestic profitability rates are to be maintained.	do	1980 U.S. petroleum production at 10.6 MMB/d, requiring imports of 7.6 MMB/d.	

(Erickson-Spann Model results).	1974	1973	$9 per barrel ($11)	do	do	do	1980 U.S. petroleum production at 10.7 MMB/d, requiring imports of 4.0 MMB/d.	
Davidson: Projected price that would equate U.S. demand with cited supplies.	1974	1974	$5.36 ($5.83)	All domestic crude oil.	Model implies that 1971 profitability rates on domestic production are adequate	U.S. policy succeeds in defeating expectations of higher prices in future; authors suggest permanent regulation of wellhead price or stiff windfall profits tax.	1980 U.S. demand for crude balances with domestic production at 16.9 MMB/d	Quoted price estimates derive from authors preferred elasticities of 1.6 for supply (prices related directly to current production rather than reserve activity) and 0.5 for demand Supply elasticity, and use of 1971 as "equilibrium" year, hinge on authors conviction that present production levels largely reflect producers withholding oil in anticipation of higher prospective prices. Authors still assume a degree of monopoly power that enables producers to gather higher-than-competitive profits at 1st 3 price and production levels.
Do	1974	1974	$5.11 ($5.56)	United States, Canadian and Venezuelan crude oil.	do	do	1980 U.S. crude production at 15.6 MMB/d, imports from Canada and Venezuela only allowed in 1971 proportions to total U.S. demand	
Do	1974	1974	$4.71 ($5.12	U.S. crude and coal production.	do	do	1980 U.S. crude production at 13.7 MMB/d, coal up to 11.0 MMB/d (oil equivalent) no net imports	
Do	1974	1974	$4.11 ($4.47)	U.S. crude production.	Model assumes competitive returns, does not specify figure.	U.S. policy, in addition to defeating price expectations, succeeds in removing producers monopoly power; authors suggest possibility of antitrust action Government regulation.	1980 U.S. crude producton matches demand at 19.3 MMB/d.	
FEA—Minimum acceptable price for cited production levels:								
(High-price, accelerated development).	1974	1973	$11 ($13)	All domestic energy sources.	10 percent discounted cash flow.	Accelerated OCS leasing availability of Naval Reserves, natural gas price allowed to rise to market-clearing levels.	1985 U.S. petroleum production of 20 MMB/d possible.	Project Independence report analyzed oil production possible at various price levels by making optimistic estimates of drilling and finding rates likely for each oil production region. For marginal supplies, 10 percent DCF return holds, but lease acquisition and rental expenses for these

SUMMARY OF OIL PRICE STUDIES—Continued

Source and nature of estimate	Date of study	Date of cost levels assumed	Price/cost estimate (1975 dollars)	Supplies considered	Profitability standard used	Policy assumptions	Volume of production/demand	Relations between price and supply/demand methods and assumptions governing results
(High-price business-as-usual).	1974	1973	$11 ($13)	All domestic energy sources.	10 percent discounted cash flow.	No departure from current regulatory, resource management policies.	1985 U.S. petroleum production of 15 MMB/d possible.	supplies are not included in price estimate In FEA's demand forecast, increasing price from $7 to $11 per barrel cuts energy demand growth from 3.2 percent to 2.7 percent per annum—or a difference of about 6 percent in the level of 1985's total enrgy demand. Regulatory tools for encouraging conservation were also considered.
(Medium-price business-as-usual).	1974	1973	$7 ($8)	do	do	do	1985 U.S. petroleum production of 11.9 MMB/d possible.	Import requirements were estimated at 5.6 MMB/d ($7 per barrel, Accelerated supply and conservation), 9.8 MMB/d ($7 per barrel, business-as-usual supply and conservation) and 1.2 MMB/d ($11 per barrel, accelerated supply and no conservation)—all for 1985.
(Medium-price accelerated development).	1974	1973	$7 ($8)	do	do	Accelerated OCS leasing, availability of Naval Reserves, natural gas allowed to rise to market clearing levels.	1985 U.S. petroleum production of 16.9 MMB/d possible.	
Stauffer: Average resource cost of U.S. production (includes profit but excludes lease acquisition royalties, and taxes).	1973	1965	$2.19 per barrel ($3.60	All U.S. petroleum and associated gas.	12 percent return on investment.	Historical Government policies.	1965's actual production.	Based finding costs on Foster data, lifting costs on data contained in earlier Steele testimony. Authors note that median resource costs falls well below the average—ie that most domestically produced petroleum cost less than the cited levels and considerably less than its current selling price. Small portion of domestic production costs more but authors assume that "cheap" oil can subsidize more expensive production to a limited degree.
Do	1973	1965	$1.54 per barrel ($2.53)	do	8 percent return on investment.	do	do	

NPC—Prices that would support cited levels of 1985 production: (Case I)	1973	1970	$6.69 ($9.25)	All present and potential U.S. energy resources are forecast under alternative assumptions.	15 percent return on net fixed assets.	Accelerated leasing of Federal mineral lands, adoption of "reasonable" environmental standards, general streamlining of Federal and local regulation to remove delays in resource development.	15.5 MMB/d U.S. petroleum production in 1985, under optimistic assumptions for reserve discoveries.	Prices are those which would provide (1) an average 15 percent return on domestic oil operation at stated production levels nd (2) funds required for exploration and development activity necessary to reach these levels. These prices and profitability do not necessarily apply to incremental reserve or production volumes and thus fail to reflect a traditional price-supply elasticity. Study adds forecast U.S. petroleum output to other domestic energy production similarly arrived at; this total
(Case IV)	1973	1970	$5.28 ($7.30)	do	do	Continued delays in resolution of environmental, health, and resource management policies.	10.4 MMB/d U.S. petroleum production in 1985 under pessimistic assumptions for reserve discoveries.	is subtracted from forecast demand to give import requirements. The demand projections themselves (3.4 percent to 4.4 percent annual increase from 1970) are independent of prices.
Steele-Derived: Crude price required for cited production levels.	1973	1972	$5.68 ($7.17)	U.S. petroleum and gas reserves excluding North Slope.	do	Steele formula modified to reflect 1969 changes in oil, taxation, enhanced environmental standards; formula assumes that exploitable mineral acreage is made readily available.	1985 crude production of 10.9 MMB/d (Excluding North Slope).	Calculations are for the production levels of the National Petroleum Council's case I treated according to Steele's regressive formula. Keyed to cumulative reserves developed, this formula yields only a very gradual increase in required real prices over time (about 2½ percent per year for the cited production path). Calculations with this model imply an elasticity of slightly more than 2 between price and volume of 1985 production.
McKelvey: Prevailing 1972 price that author argued would be adequate for cited production under his assumptions.	1972	1972	$3.40 $3.80 ($4.30 to $4.80)	U.S. oil and gas reserves.	Implies competitive rates of return.	1972 import regulations continue, Naval Reserves 1 and 4 allowed full production, accelerated OCS leasing, 2 Alaska pipelines built by 1985.	1985 U.S. petroleum production at 16.8 MMB/d.	Testimony viewed U.S. energy position dependent on removal of developmental delays availability of exploitable acreage, rather than any significant boost in real prices.

SUMMARY OF OIL PRICE STUDIES—Continued

Source and nature of estimate	Date of study	Date of cost levels assumed	Price/cost estimate (1975 dollars)	Supplies considered	Profitability standard used	Policy assumptions	Volume of production/demand	Relations between price and supply/demand methods and assumptions governing results
IPAA, derived: Combined price of oil and gas (5.4 thousand cubic feet equals 1 barrel) required for cited production levels.	1972	1972	$4.13; 77 cents per thousand cubic feet (gas) ($5.21; 97) cents	U.S. petroleum and gas reserves, excluding North Slope.	Implies historical rates of return on domestic production.	IPAA formula modified to reflect 1969 changes in oil taxation; formula assumes that exploitable mineral acreage is made readily available.	1985 U.S. production of 25 MMB/d of crude and natural gas equivalent.	Calculations are for the production levels of the National Petroleum Council's case I treated according to IPAA's regressive formula. This formula presumes a continuation of the period 1952–72's average success in finding oil per constant dollar expended. This logic yields an elasticity of approximately 1.4 between real price and reserve development and eventually production. Demand not projected by IPAA formula.
Crude price required if gas is sold at 50 percent parity with oil.	1972	1972	$5.75; 53 cents per thousand cubic feet (gas) ($7.27; 67 cents)	do	do	do	do	
Foster Associates: Current production and finding costs of actual production (includes lease acquisition and	1970	1967	$1.93 to $1.98 ($3.09 to $3.17)	Gulf of Mexico crude production.	No return to capital included in cited cost calculations; these costs, when matched with	Historical Government actions.	Actual 1957 to 1967 production in Gulf of Mexico.	Analysis, done for Interior Department, reviews previous on and off-shore cost experience as part of overall forecast of U.S. energy position. Report, completed in 1970, did not consider possibility of

dry hole costs, excludes profit, royalties and income taxes).					prevailing prices produced 7.2 to 8 percent return on book capital, 5 to 5.4 percent DCF.			"revolutionary change" in market conditions such as quadrupling of world oil prices, nevertheless forecast U.S. oil imports remaining below 4 MMB/d during period 1975–80.
Do	1970	1967	$2.10 ($3.36)	Onshore southern Louisiana crude production.	Same, but 11.9 percent on book capital 6.4 percent DCF.	do	Same for onshore Louisiana.	Do.
Do	1970	1967	$1.85 per barrel ($2.95)	Other U.S. crude production.	Same, but 7.2 percent on book capital 4.3 percent DCF.	do	Same for other continental United States.	Do.

NOTES

1. Source and nature of estimate.—Above cited title for studies; where several estimates are given, subtitles in parentheses.

2. Date of study.—Date of official publication; this date would of course be most important in influencing the view of the resource base held by authors.

3. Date of cost levels assumed.—Year in which development costs were measured; in some cases this results in an explicit estimate in "year × dollars"—the same effect has been taken as implicit when authors did not present it as such but grounded their estimate on a particular year's cost figures.

4. Price/cost estimate.—Unit-revenues per barrel of crude that is consistent with, or produces, the results given in other columns; first figure is authors' published estimate, second figure in parentheses is their estimate converted into 1975 dollars (by percent change in GNP deflator from date of cost levels assumed to 1975.) Conversion is only to number of significent figures in original estimate.

5. Supplies considered.—All energy sources considered by authors in arriving at their estimate whether or not each of these makes any contribution to the production figures in the next-to-last column.

6. Profitability standard used.—Explicit profit gage added to capital costs by authors or, in the case of econometric studies, the implicit continuation of sample period profitability.

7. Policy assumptions.—Federal, State, local actions needed to produce authors' price, production results.

8. Volume of production/demand.—Production associated with given price estimate; may be historical or projected figure; where authors have assigned a demand level to a particular price. this is cited. In this column "crude" means crude oil only, "petroleum" means crude plus natural gas liquids.

9. Relations between price etc.—Attempt to characterize those aspects of the study that are most decisive in determining its results. Where some thing like an elasticity of supply or demand is contained in study, this is noted.

"DOMESTIC OIL AND GAS AVAILABILITY", CHAPTER FOUR OF US ENERGY OUTLOOK, NATIONAL PETROLEUM COUNCIL (1972)

Chapter Four
Domestic Oil and Gas Availability

Introduction

Numerous factors affect the supply of oil and gas from domestic sources. Each of these factors must be identified and quantified to develop a projection of supply for any future period of time. This study considered relevant items in the following five broad categories:

- Resource availability
- Industry capability
- Government policies
- Economic climate
- Future technology.

Initial Appraisal

In the NPC's Initial Appraisal, a projection of supply was developed utilizing one specific set of assumptions. For the purpose of simplicity, the Initial Appraisal assumed a "status quo" outlook over the study period, as indicated by the following:

> Supply-demand relationships are projected assuming that current government policies and regulations and the present economic climate for the energy industries would continue without major changes throughout the 1971-1985 period.*
>
> The following assumptions governed the oil and gas analyses:
>
> 1. Recent physical levels of oil exploration and development drilling activity and exploration success trends would continue into the future.
> 2. The level of capital investment in gas exploration and development drilling activity would remain relatively constant and the past trends in the results of such activity would provide the basis for future expectations.
> 3. After domestic oil production capacity is reached, remaining requirements would be satisfied by imports. It was also assumed that political, economic and logistical considerations would not restrict the availability of foreign oil.
> 4. All presently feasible sources of gas supply, domestic and foreign, would be utilized. It was also assumed that political, economic and logistical considerations would not restrict the availability of foreign gas. . . .
>
> These assumptions are generally optimistic. In view of past trends, the assumed levels of oil and gas exploratory activity, in particular, are not likely to be realized without substantial improvements in economic conditions and government policies.*

The Initial Appraisal made no attempt to analyze the economic feasibility of the case presented. Levels of activity and physical results were merely projected into the future using an assumption of constant price, without examining the economic implications.

Objective of Second Phase

The objective of this oil and gas study is to examine in more detail the factors which affect future supplies, with particular attention to increasing indigenous supplies. A methodology capable of analyzing the numerous parameters that could affect future domestic petroleum supply levels was developed.

General Approach—Conventional Supply

Ranges were assumed for drilling levels, finding rates and additional recovery efforts to develop new oil and gas supplies. The costs of achieving these activity levels and resultant production rates were calculated. A range of returns on investment (net income as a percentage of net fixed assets) was selected and "prices" required to provide these re-

* NPC, *U.S. Energy Outlook: An Initial Appraisal 1971-1985*, Vol. II (November 1971), p. *xvii*.

turns on the net fixed assets were computed.* This methodology provides a great deal of information on the relationship between oil and gas supplies and the economic climate required to support the supply projections. It additionally provides a basis for evaluating the impact on supply and unit "price" of varying assumptions on physical, economic and government policy factors.

The method adopted cannot provide precise solutions on price supply elasticity. Such a determination would have to separate price from all other motivational considerations, and there appears to be no way to isolate price effects from historical data in a purely objective manner. Further, any analysis of future supply price relationships must recognize that they will undoubtedly change considerably from those experienced in the past. The historical record of oil and gas discoveries reflects the influence of resource availability, technological capabilities, governmental policies and cost factors, none of which will necessarily be duplicated in the future. Shifts in these factors are often difficult to predict or quantify, yet the accuracy of any prediction concerning the response of oil and gas supplies to changes in price is dependent upon future changes in these other factors.

These uncertainties typify some of the risks inherent in oil and gas exploration and development. As a result, any given level of prices may result in increments of new supplies which exceed or fall short of anticipation. However, the methodology adopted does provide insights into supply price relationships and thus serves as a valuable tool to facilitate the development of sound energy policies by those vested with this responsibility.

The analysis was performed on a geographic region-by-region basis, taking into account variations in drilling, finding experience, costs, degree of maturity, etc. The regional results were subsequently combined to present total U.S. results. The geographic distribution used in the Initial Appraisal (shown in Figure 5) was adopted with minor modifications.

The projection period began with 1971 because the latest published data available at inception of this phase of the study were for 1970. As a result, the 1971 projections will not necessarily agree with actual experience. No attempt has been made in this report to reconcile any minor differences between the 1971 projections and actual data. However, in general, the results to date do not deviate greatly from the projections, and the differences are not of such magnitude as to cast doubt on the validity of the methodology or findings.

A computer program was developed to facilitate the processing of data because of the multitude of variables involved in implementing the methodology and the need for making a large number of repetitive calculations. The program has no internal optimizing logic or mechanisms by which it can relate calculated economic results to investor motivation or incentives.

Within the computer program, oil supply—including associated-dissolved gas and plant liquids—and related economics were calculated for the lower 48 states plus southern Alaska. Non-associated gas supply, including lease and plant liquids, and related economics were computed for only the lower 48 states. Projections of North Slope oil and gas and southern Alaska non-associated gas operations were made independently rather than through the computer program. These segments of Alaskan operations were not included in the "price" calculations because of the lack of operating experience and data and logistic uncertainties. Reserve additions, production and capital requirements for these areas are incorporated later in this chapter. For ease of reference in the remainder of this report, the area analyzed using the computer program will be labeled "lower 48 states" even though southern Alaskan oil operations are included.

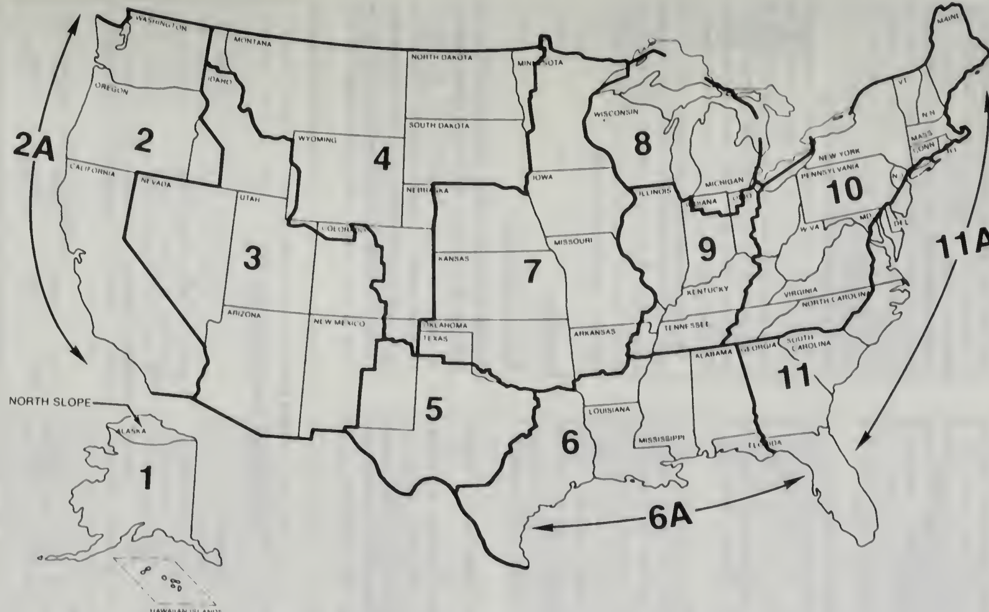
Cases Analyzed

The two most significant variables involved in projecting future domestic production of oil and gas are (1) *finding rate*—the volume discovered per unit of drilling—and (2) *drilling rate*—the footage drilled annually.

Regional analyses of historical finding rates indicate a range of results which cannot adequately be represented by a single line extrapolation. Therefore, high and low finding rates were projected for each region.

To determine the possible range of future do-

* As used in this study "price" does not mean a specific selling price as between producer and purchaser and does not represent a future market value. The term "price" is used to refer generally to economic levels which would, on the basis of the cases analyzed, support given levels of activity for the particular fuel.



Regional Boundaries: Region 1 – Alaska and Hawaii, except North Slope, Region 2 – Pacific Coast States, Region 2A – Pacific Ocean, except Alaska, Region 3 – Western Rocky Mountains, Region 4 – Eastern Rocky Mountains, Region 5 – West Texas and Eastern New Mexico, Region 6 – Western Gulf Basin, Region 6A – Gulf of Mexico, Region 7 – Midcontinent, Region 8 – Michigan Basin, Region 9 – Eastern Interior, Region 10 – Appalachians, Region 11 – Atlantic Coast; Region 11A – Atlantic Ocean.

Source: NPC, *Future Petroleum Provinces of the United States* (July 1970) – with slight modification.

Figure 5. Petroleum Provinces of the United States.

mestic production, three drilling rates were investigated: (1) a high rate of drilling growth, (2) a medium rate of drilling growth, and (3) a continuation of the declining historical trend. The highest rate of drilling growth provides by 1985 annual drilling rates exceeding the industry all-time high achieved in 1956 following the rapid expansion after World War II.

Six oil and gas supply cases resulting from combinations of these two finding rates and three drilling rates were analyzed. Also, the initiation of production from the North Slope was delayed in two of the cases. The configuration of these variables, as they define the six cases investigated, is outlined in Table 32.

For brevity, four of these six cases (I, II, III and IV) were selected to display the results whenever possible. These cases represent the three drilling rates and cover the widest range of supply results. Case I is the highest supply case; Cases II and III are intermediate supply cases, combining the medium drilling rate with both the high and low finding rates; and Case IV is the lowest supply case and includes delays in Alaskan development.

General Approach — Supplemental Supply

The principal sources of domestic oil and gas supply during the 1971-1985 period will be conventional production. However, sufficient progress in research and development (R&D) and/or experience in certain energy fuel conversion applications has been made to support a reasonable range of estimates for certain potential supplemental sources of supply. This category of supply includes: liquefaction and gasification of coal, production of liquids from oil shale and tar sands, reforming of certain petroleum liquids to produce substitute natural gas (SNG), and utilization of nuclear explosives to stimulate production in low-productivity natural gas reservoirs.

Analyses of the volumes, capital investments and required "prices" for the production of oil or gas from coal, oil shale and tar sands are contained in Chapters Five, Seven and Eight, respectively. Analyses of SNG production and nuclear explosive stimulation are contained later in this chapter.

Generally, such forms of supply will require large capital investments and "prices" considerably higher than those for conventional supplies at present and will make limited contribution to total supply in the projected period.

Summary

Reserve Additions

Table 33 shows actual and projected reserve additions of petroleum liquids and natural gas in the lower 48 states. In addition to the reserve additions shown, it is estimated that average annual reserve additions in Alaska will range between 0.3 and 0.6 billion barrels of petroleum liquids for Cases IV and I, respectively, and between 1.3 TCF

TABLE 32

OIL AND GAS CASES ANALYZED

Variable	Highest Supply I	IA	II	III	IVA	Lowest Supply IV
Finding Rate	High	Low	High	Low	High	Low
Drilling Rate	High Growth	High Growth	Medium Growth	Medium Growth	Current Downtrend	Current Downtrend
North Slope Production Starts						
Oil	1976	1976	1976	1976	1981	1981
Gas	1978	1978	1978	1978	1983	1983

TABLE 33

SUMMARY OF ANNUAL RESERVE ADDITIONS IN LOWER 48 STATES

	Actual	Projected Case I	Case II	Case III	Case IV
	Petroleum Liquids (Billion Barrels per Year)				
1960	3.1				
1965	3.9				
1970	3.4				
1975		3.8	3.7	2.9	2.5
1980		4.9	4.3	3.5	2.7
1985		5.3	4.7	3.7	2.6
	Total Natural Gas (TCF per Year)				
1960	13.8				
1965	21.2				
1970	11.1				
1975		19.3	17.3	11.6	8.8
1980		27.2	21.8	14.2	7.4
1985		25.9	21.1	14.1	5.9

(Case IV) and 4.2 TCF (Case I) of gas over the 15-year period 1971-1985.

Production

Tables 34 and 35 show the projected daily average production of petroleum liquids and the annual production of natural gas.

TABLE 34

SUMMARY OF WELLHEAD PRODUCTION* PETROLEUM LIQUIDS (MMB/D)

	Actual	Projected Case I	Case II	Case III	Case IV
	Lower 48 States				
1960	8.0				
1965	8.9				
1970	10.9				
1975		9.9	9.9	9.5	9.4
1980		10.8	10.4	9.2	8.6
1985		12.0	11.1	9.3	8.0
	Alaska				
1960	-				
1965	-				
1970	0.2				
1975		0.3	0.3	0.3	0.2
1980		2.8	2.5	2.4	0.3
1985		3.5	2.8	2.5	2.4
	Total United States				
1960	8.0				
1965	8.9				
1970	11.1				
1975		10.2	10.2	9.8	9.6
1980		13.6	12.9	11.6	8.9
1985		15.5	13.9	11.8	10.4

* In addition to these volumes of conventional production, projected volumes of synthetic liquids are discussed in Chapters Five and Seven. Oil supply from all sources is shown in Table 82.

Required "Prices"*

Actual "prices" for several prior years and the computed average "prices" required for a 15-percent return on net fixed assets to achieve the levels of reserve additions and production for all cases investigated are shown in Table 36. These are average "prices" for all vintages and all qualities of oil and gas. Five rates of return on net fixed assets between 10 and 20 percent were investigated; only the mid-level of 15 percent is shown for the projection in Table 36.

Conclusions and Implications

Resources of Oil and Gas

The volume of domestic oil and gas remaining to be found will not be a limiting factor on domestic supply prior to 1985. There remains to be discovered almost as much oil-in-place (OIP) and twice as much non-associated gas as had been found by the end of 1970.

The geographic location of the remaining potential resources is an important factor. About half of the remaining oil and gas is estimated to lie in

* Not a specific selling price as between producer and purchaser and does not represent a future market value. The term "price" is used to refer generally to economic levels which would, on the basis of the cases analyzed, yield the selected level of return on net fixed assets for given levels of activity for the particular fuel under the assumptions made. For a discussion of "constant" and "current" dollars, see Glossary.

TABLE 35

SUMMARY OF WELLHEAD PRODUCTION*—
TOTAL NATURAL GAS
(TCF/Year)

	Actual	Projected Case I	Case II	Case III	Case IV
		Lower 48 States			
1960	13.0				
1965	16.3				
1970	22.2				
1975		23.5	23.4	21.8	21.6
1980		24.2	22.8	19.1	17.1
1985		26.2	23.0	17.5	13.2
		Alaska			
1960	–				
1965	–				
1970	0.1				
1975		0.2	0.2	0.2	0.2
1980		1.7	1.5	1.3	0.2
1985		4.4	3.5	2.9	1.8
		Nuclear Stimulation			
1970	–				
1975		–	–	–	–
1980		0.2	0.1	0.1	–
1985		1.3	0.8	0.8	–
		Total United States			
1960	13.0				
1965	16.3				
1970	22.3				
1975		23.7	23.6	22.0	21.8
1980		26.1	24.4	20.5	17.3
1985		31.9	27.3	21.2	15.0

* In addition to domestic wellhead production, volumes of substitute natural gas from liquid hydrocarbon feedstocks (discussed later in this chapter) and coal (discussed in Chapter Five) were projected. Gas supply from all sources is shown in Table 83.

the frontier areas of Alaska and offshore, while very little may be left in some of the mature inland provinces.

The key factors determining the volume of these resources which will be developed during the 1971-1985 period are access to prospective areas, drilling rates and finding rates. Appropriate economic and political conditions are also essential to the attainment of the projected results.

Drilling Rates and Additonal Recovery Activity

The industry has been in a phase of diminishing activity for several years. With positive incentive and areas to explore, the petroleum industry can reverse its recent trend of declining drilling activity and begin expanding to rates achieved in the post-World War II decade. Such a reversal in drilling rates, without a change in the finding rate, results in increasing 1985 total liquids and gas production (including Alaska) by about 2.6 MMB/D and 8 TCF per year above the level that would occur if the historical downtrend in drilling were continued (Case IA *vs.* Case IV).

In addition to increased exploration activity, adequate incentives could stimulate the oil industry to expand its application of secondary and tertiary oil recovery processes. By 1985, these additional recovery methods might account for about half of the oil production from the lower 48 states.

Finding Rates

The difference between the projected high and low finding rates is substantial—the high finding rate discovers approximately half again as much as the low finding rate per foot of hole drilled. Measured in terms of wellhead production in 1985, assuming the medium growth drilling rate (Cases II and III), the high finding rate provides about 2 MMB/D of oil and 6 TCF of gas per year more than the low rate. The impact on required unit "prices" to yield a 15-percent return would be a reduction of \$0.42 per barrel and \$0.13 per MCF.

Lead Time

The lead time between a producer's decision to expand exploration activity and the resultant increase in oil and gas production is unavoidably long. Geological and geophysical work must be done to identify new drilling prospects, adequate funds to finance the effort must be made available, land must be leased, drilling rigs must be acquired (or built), manpower trained, drilling accomplished, production and transportation facilities built, and gas contracted. The lead time in the frontier areas where the major potential exists can be as long as 5 years or more. Thus, not only are immediate incentives required, but the *expectation* by the in-

TABLE 36

SUMMARY OF AVERAGE REQUIRED "PRICES"—LOWER 48 STATES
(Constant 1970 Dollars)

		Projected (15% Return on Net Fixed Assets)					
		High Finding Rates			Low Finding Rates		
	Actual*	Case I	Case II	Case IVA	Case IA	Case III	Case IV
	Crude Oil "Price" ($/Bbl)						
1960	3.33						
1965	3.26						
1970	3.18						
1975		3.65	3.63	3.54	3.70	3.67	3.57
1980		4.90	4.73	4.26	5.16	4.95	4.39
1985		6.69	6.18	5.06	7.21	6.60	5.28
	Gas Field "Prices" (¢/MCF)						
1960	16.2						
1965	17.8						
1970	17.1						
1975		26.7	26.2	25.1	28.5	27.9	26.6
1980		33.7	31.8	27.6	40.9	37.8	31.6
1985		43.6	39.8	31.2	59.4	53.0	38.7

* Actual data are average wellhead values at unspecified rates of return reported by the Bureau of Mines and converted to constant 1970 dollars.

dustry of a stable, satisfactory economic and political climate is essential.

Price Incentive

The most effective economic incentive would be to allow prices to increase to the level at which the industry can attract and internally generate the risk capital needed to expand activity to its maximum capability. This requires both a fair return on total investment (e.g., return on net fixed assets), as well as the anticipation of attractive returns on current and future investments.

During the last 10 to 15 years, real prices of oil and gas at the wellhead have declined while real costs have been increasing. As a result, both drilling activity and addition of new reserves have declined rapidly. Assuming a 15-percent annual rate of return in constant 1970 dollars, 1985 average oil "prices" may have to range from $5.06 to $7.21 per barrel, and 1985 average gas "prices" may have to range from $0.31 to $0.59 per MCF to support the activity levels assumed (Cases IA and IVA). If prices for gas found prior to 1971 are prevented from increasing by regulatory or contractual restrictions, the required "price" in 1985 for gas found after 1970 would be on the order of 30 to 50 percent greater than the average "prices" calculated.

Even a continuation of drilling activity along the current declining trend will require "price" increases of about $2.00 per barrel and $0.15 per MCF by 1985 if the petroleum industry is to realize a 15-percent return on its net fixed assets.

Government Policies

Price increases alone will not assure substantial increases in the exploration for and development of oil and gas supplies. They must be accompanied

by reasonable, consistent and stable governmental policies specifically designed to encourage the development of additional domestic oil and gas production. Policy issues of particular importance include leasing of government lands, environmental conservation, taxation, natural gas price regulation and oil import quotas.

Leasing of Government Lands

Recently, adversary proceedings and procedural uncertainties and delays pertaining to environmental concerns have resulted in severely restricting industry access to the frontier areas that contain the most potential for the recovery of oil and gas. Such issues must be resolved more expeditiously in the future so that long-range project planning, which includes logistical and transportation considerations, may proceed.

The amount of federal lands leased in the offshore areas must increase substantially during the 1971-1985 period to achieve the supplies projected. For example, in Case II, the total offshore acreage required for exploration increases from about 600,000 acres per year actually leased in 1970 to almost 2,300,000 acres per year in 1985—an increase of almost 400 percent. Also, if acreage in the California offshore areas is not added to the Department of the Interior's announced lease sales schedule, the 1985 production rate would be about 700 MB/D less than projected. Announcing a lease sales schedule showing increasing acreage offered per sale, as well as increased sale frequency, would also facilitate more effective industry planning in the exploration for and development of new reserves in federal areas.

In the case of the Alaskan North Slope, not only has exploration access been restricted but efforts to produce the largest oil field found on the North American Continent have also been frustrated. The lack of any return on the more than $1.5 billion already spent on the North Slope by the industry to date has adversely affected the economics of participants and severely restricts the availability of capital to finance further industry expansion.

Unless federal policies are adopted to make the necessary offshore acreage available in a timely fashion and to permit marketing of offshore and Alaskan reserves, the U.S. consumer will be deprived of about 40 percent of projected 1985 domestic production potential.

Environmental Conservation

Use of land and offshore areas for development of natural resources in a manner that is compatible with environmental quality standards is both feasible and necessary. The technology is currently available at reasonable expense to assure compliance with practical and reasonable environmental objectives.

Taxation

The effects of changes in the statutory depletion rate, preference tax rates, job development credit, and implementation of exploration tax credit on required "prices" were calculated, assuming no change in exploratory activity or results.

If the depletion allowance is eliminated under the conditions of Case II and III, then "price" increases ranging up to $1.00 per barrel and $0.07 per MCF would be required to maintain industry profitability at a 15-percent return on net fixed assets. The implementation of a tax credit (12.5 percent for investment in exploration and additional recovery) could result in a reduction of required "prices" of $0.38 per barrel and $0.03 per MCF by 1985.

The motivational forces which are activated by tax changes and their impact on industry response are believed to be substantial, but they cannot be directly quantified by the methodolgy used. Data pertinent only to the exploration and production function cannot be aggregated in a manner that avoids distortion. In other words, the "average" would be an unrealistic composite of corporations, individuals, partnerships, etc., that are each subject to different exposure to tax liabilities.

Natural Gas Price Regulation

During the 1960's, demand for natural gas was artificially stimulated, and development of new supplies was restricted by FPC pricing policies that held gas prices below their competitive level in the marketplace. Wellhead gas production in the United States increased at an unprecedented rate in this decade, from 13.0 TCF in 1960 to 22.3 TCF in 1970. The large backlog of proved reserves of

gas which made this rapid increase in production possible is no longer available to support any substantial further growth. Future increases in production must depend primarily on new reserve additions.

If the supply capability of the domestic natural gas industry is to continue to expand in response to demand, the FPC regulatory system must be altered to allow natural gas to reach its competitive price level and thereby provide the incentives necessary to find, develop and market additional natural gas supplies. Similarily, if supplemental domestic sources of supply from coal gasification, SNG and nuclear-explosive stimulation are to make any substantial contribution, the regulatory system must demonstrate sufficient flexibility to permit economic incentive to reflect both the expense and risk involved. This same set of regulatory circumstances must apply to imports of both conventional gas and LNG.

Oil Import Quotas

A system of effective, equitable oil import quotas is essential to providing the incentive to expand domestic supplies of energy so that over-dependence on foreign sources for energy supplies can be avoided. Such over-dependence on foreign sources can make the United States vulnerable to interruption of petroleum supply from either military action or shutdown for political reasons. Without the deterrent effect of a strong domestic oil industry, producing countries could more easily threaten economic sanctions and boycotts to influence U.S. international policies. Moreover, major interruptions of energy imports could severely hamper the functioning of the U.S. economy.

Oil import quotas tend to encourage development of all indigenous energy resources. For example, since oil exploration and gas exploration are generally joint activities using the same people, techniques and equipment, the availabilities of these two fuels are inextricably related. Without oil import quotas, domestic oil and gas availability would decline. The development of domestic synthetic fuels could also be retarded by the lack of economic incentives caused by the threat of unrestricted imports at a price which would not yield an adequate return for domestic producers of these fuels.

Technology

Continuation of past trends of evolving technology have been implicitly assumed in this study. However, if major breakthroughs are experienced, such as the ability to achieve the high finding rate with consistency, the effects could be quite dramatic. A breakthrough in additional recovery technology would result in large supply increases. For example, a 2-percent increase in the cumulative oil recovery factor over the 1971-1985 period could amount to an additional 1 to 2 MMB/D of oil production in 1985.

Technological improvements in drilling capability and in the design and construction of production facilities are essential if the tremendous potential of the Arctic offshore is to be realized. Some assurance that this area will be opened to exploration and development is needed if industry is to undertake the research required for resolution of the problems associated with operations in the Arctic.

Private industry has developed most of the existing exploration and production technology and has the best technical capability to develop the kinds of new technology needed for future development of the Nation's oil and gas resources. This technical capability will be used effectively by private industry, provided there is reasonable incentive to do so.

Methods of Analysis

General

Oil and gas exploration, development and production operations are different but related facets of the same business. Analysis should not totally segregate oil and gas operations because it is inevitable that some volumes of associated-dissolved gas and, occasionally, non-associated gas reservoirs will be found as a result of oil exploration. Conversely, exploration for gas sometimes results in the discovery of oil reservoirs, and gas well production is often accompanied by the recovery of petroleum liquids. Therefore, although pre-selected objectives account for most of the resulting types of production, exploration for either oil or gas ultimately leads to the discovery and production of both.

Two of the key elements of an analytic method-

ology for projecting the results of oil and gas exploratory and development operations are (1) the amount of drilling done (drilling rate) and (2) the amount of oil and/or gas found per foot drilled (finding rate). Utilizing compatible sets of judgments for oil and gas on finding and drilling rates, as well as for many other variables, allowed the design of a methodology capable of making separate but parallel calculations for each fuel.

This methodology analyzed the historical amounts of oil found as a function of oil drilling and, in like manner, the amount of gas found as a function of gas drilling. These historical relationships were used to project the results of future activity levels. By this approach, past *directionality* (fraction of the times that oil, rather than gas, is found when looking for oil, and vice versa) was implicitly recognized in an empirical manner, and the explicit quantification of directionality in the projection period was unnecessary. The selection of a range of future trends of oil and gas finding rates (as discussed later) also helped eliminate any need to quantify directionality. This treatment is possible only if the ratio of oil drilling footage to gas drilling footage is reasonably constant during both the historical period used for determining the finding rates and for the projection period.

Historically, productive and non-productive footage drilled is reported separately and is further classified as exploratory or development footage. In this analysis, non-productive footage was allocated to oil and gas by region according to productive footage ratios. This resulted in 69 percent of the total footage drilled in 1970 being allocated to oil and 31 percent to gas (see Figure 6). Also shown is the projected drilling footage for Cases I and IV which cover the highest and lowest drilling activity levels. Oil and gas drilling in both cases shown, as well as in the medium growth cases (Cases II and III), remains near the 70- to 30-percent split experienced since 1960.

The extent to which the ratio of oil to gas drilling can deviate from the historical ratio without distorting the calculated results is uncertain. There-

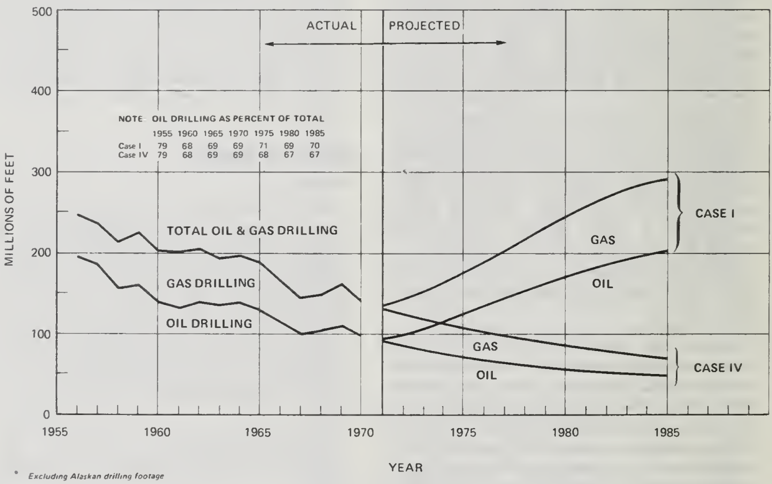


Figure 6. Oil and Gas Drilling Footage—Total United States (Million Feet).*

fore, the methodology used in this analysis is not recommended for general application where the future drilling mix may vary appreciably from historical ratios.

In addition to calculating reserve additions and production, the methodology also calculated required capital investments for specified levels of activity and accompanying required "prices" for oil and gas at a range of rates of return on net assets. Sufficient flexibility has been provided in the method developed (displayed as a schematic in Figure 7) to handle separately such differences in the two fuels as producing characteristics and additional recovery possibilities.

Although oil supply, gas supply and economics are calculated separately, each segment interacts with the others at several appropriate points in the procedure so that oil and gas are interlocked and cannot be analyzed independently. Both oil and gas supply segments are calculated on a regional basis, and the results are then aggregated to provide totals for the regions considered.

Oil Supply Procedures

The first item calculated was reserve additions resulting from oil exploratory drilling. Based on historical data, both a high and low future oil finding rate for each region was established to encompass the range of expectations. These rates were expressed in terms of barrels of oil-in-place found per exploratory foot drilled in search of oil and varied as a function of cumulative exploratory oil drilling.

The volume of oil-in-place found yearly in each region was determined from the product of the oil finding rate and the exploratory drilling rate. The oil reserves added from exploratory drilling were determined by applying the appropriate primary recovery factor to the oil-in-place discovered. The reserves added by application of secondary and tertiary recovery processes were calculated and added to the exploration results, thus determining total annual oil reserve additions.

Annual oil production was scheduled as a function of the remaining reserves at the beginning of

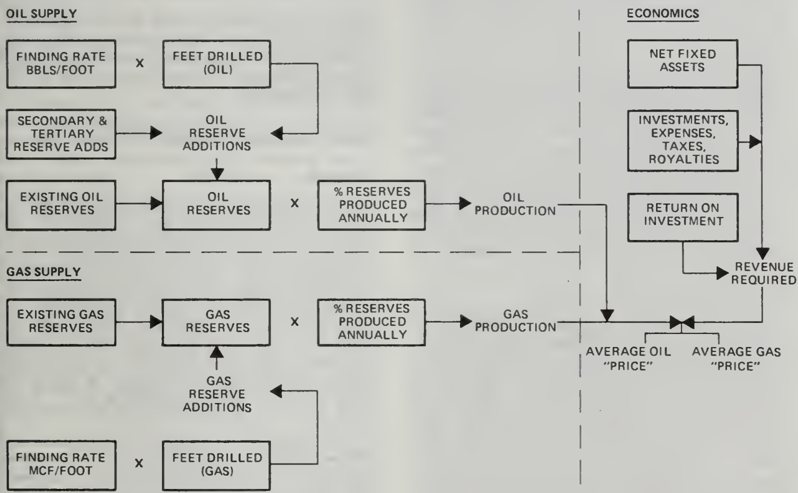


Figure 7. Oil and Gas Supply—Economic Methodology.

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each year by applying appropriate factors in the various regions to account for their particular oil recovery mechanisms and reservoir characteristics. Associated-dissolved gas reserves and production were estimated by applying calculated gas/oil ratios to the oil production volumes.

Gas Supply Procedures

Non-associated gas reserve additions and resulting production were determined in a manner very similar to that used in making the oil calculations. However, gas finding rates were expressed as gas reserves found per foot of total gas drilling, including both exploratory and development well footage.

Gas production was calculated regionally, using one schedule of factors which related annual production to proved reserves estimated as of December 31, 1970, and a second schedule of factors which related annual production to reserves subsequently added.

Reserves and production of natural gas liquids contained in the natural gas—both non-associated and associated-dissolved—were calculated by applying gas/liquid ratios derived from historical data.

Because of the inherently high primary recovery factors normally experienced with gas well production, no additional recovery of reserve additions are calculated. Nuclear-explosive stimulation does achieve higher production rates, but its application is regarded as appropriate only in those areas where conventional well completion techniques do not permit commercial operation. Therefore, this technology which is separately discussed could be thought of as increasing the reserve potential.

Economic Procedures

The investments and expenses required to achieve the projected oil and gas drilling and producing levels were calculated from regional historical cost trend relationships and anticipated future drilling depths and locations. Other economic parameters, such as taxes, royalties and depreciation, were also quantified. Beginning with estimates of the industry's net fixed assets both in oil and gas production facilities as of December 31, 1970, the average net fixed assets for each fuel were determined for each subsequent year.

The annual net income necessary to yield various levels of return on the net fixed assets was calculated. These returns are defined as the ratio of the annual net income after tax (before interest charges) to the average net fixed assets (average of beginning- and end-of-year net investment in property, plant and equipment). A broad range of returns was investigated as an alternative to making an arbitrary selection of a specified return level that would be required by an industry composed of numerous individuals and firms experiencing diverse economic conditions. Tax liabilities and all other expenses and burdens on production such as royalties were also computed to arrive at the total revenue required for each rate of return. The revenues from associated-dissolved gas were credited to the oil sector; revenues from gas liquids were credited to the gas sector.

Once the required oil and gas revenues were calculated, they were converted to unit revenue or "price" * schedules. Dollars per barrel and cents per MCF were computed by dividing the required annual oil and gas revenue by the volumes of oil and gas which are marketed. The "prices" calculated in this manner represent *average* U.S. crude oil and natural gas "prices" in the field. The method used makes no attempt to calculate "price" by geographic area, by quality of product, or by year of discovery.

Considerations Regarding Methodology

General

This methodology does not address all of the factors that motivate individual investors either to take the risks necessary to explore for and produce increasing quantities of oil and gas or, conversely, to retrench in their operations. The program has no internal optimizing logic or mechanisms by which it can relate calculated economic results to investor motivation or incentives. Therefore, the method of analysis should not be used to forecast explicitly or calculate the elasticity of supply to price. However, it can be used to estimate unit

* Not a specific selling price as between producer and purchaser and does not represent a future market value. The term "price" is used to refer generally to economic levels which would, on the basis of the cases analyzed, provide a specified rate of return on net fixed assets for given levels of activity for the particular fuel.

revenues for oil and gas required to support assumed levels of exploration and production activity based on the industry achieving specified rates of return on its net fixed assets.

This method does not separately compute the "prices" required to achieve an acceptable return on incremental new investments. Rather, it calculates the *average* "price" needed to yield a specified return on total net fixed assets, thereby combining past discoveries for which the major investments have previously been made and projected future discoveries with their accompanying costs. In an increasing-cost industry, the resultant *average* "prices" tend to be lower than those needed to justify incremental new exploratory and development investments so that the price incentive required to encourage new investments will be higher than the average "prices" calculated.

It is possible to utilize the average "price" calculations from the computer program to estimate the approximate rate of return on new investments provided by such average "prices." This subject is addressed further in the oil and gas economics section.

Returns on net fixed asset calculations were used for oil and gas because they recognize the large base of assets and reserves built up in the past as well as new activities and can be calculated with a minimum of assumptions. This return on net fixed assets is not the same as the more commonly reported *return on shareholders' equity* (also termed *return on invested capital* or *return on net worth*). To attempt to calculate return on shareholders' equity would require making a large number of additional assumptions on allocation of corporate accounts such as working capital (inventories, cash, receivables and payables, etc.), other long-term assets (pre-payments, deferred charges, goodwill etc.), and long-term liabilities (primarily debt) that might be appropriate for domestic exploration and production operations. No historical data are available for estimating these items, and to attempt to do so would add additional uncertainty. Published estimates of historical returns on domestic exploration and production net fixed assets are available and provide a basis for comparison of projections with past performance.* These historical data on returns on net fixed assets are generally parallel but substantially higher than return on shareholders' equity.

To show the sensitivity of the returns to the base used, an estimate of working capital was added to the asset base. Although there are no reliable published data available on working capital assignable to only the exploration/production activities, 20 percent of net fixed assets was considered to be a reasonable estimate. The addition of working capital at that level reduces the return by about one-sixth so that a 15-percent return on net fixed assets would be 12.5 percent on total capital employed.

Oil and Gas Drilling

In establishing the rate at which drilling could increase annually for the high growth case (Case I), it was assumed that the industry could expand at a rate high enough to return to a drilling level equal to the maximum achieved since World War II by oil and exceed the previous peak year of gas drilling in 1961 by almost 50 percent. However, it is also necessary to recognize the obstacles that must be overcome to achieve that result. Since 1956, the industry has experienced a decline in domestic drilling activity which has resulted in dismantling a large number of rigs and having trained drilling personnel seek other employment. As a consequence, there are currently insufficient drilling rigs and experienced crews to support such a reversal in drilling activity without the manufacture of new equipment and an intensive period of personnel training.

Drilling effort cannot be radically and quickly shifted from one region to another. Seismic equipment and techniques used on land cannot be applied to offshore areas without modification. Also, lightweight drilling equipment with relatively shallow depth limitations cannot be utilized in areas where the objective reservoirs, if present, are at extreme depths. Large rigs, designed specifically for deep-well drilling, cannot be used economically to drill shallow wells. In most instances deep onshore drilling equipment cannot be used to implement a substantial increase in offshore drilling activity without extensive, costly and time-consuming modifications. The building or modification of specially designed equipment for Arctic operations

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* "Financing the Petroleum Industry During the 1970's," Paper Presented by Kenneth E. Hill at the API Division of Finance and Accounting, Dallas, Texas, June 11, 1970.

is expensive and requires significant lead time. Also, the transportation and other related logistics factors pertaining to Arctic operations impose highly significant seasonal limitations on movement and operation even if cost were not a constraint. Therefore, in addition to an improved economic climate to overcome existing equipment and personnel availability obstacles, reliable expectations of access to frontier and offshore areas having future potential must exist, and continued technological improvement in drilling and logistics must be pursued.

Another obstacle to rapid drilling expansion is the lead time required to conduct increased geophysical and geological activities to locate drilling prospects, as well as the time needed to obtain leases and drilling permits.

Federal Offshore Lease Availability

The offshore areas of the United States account for a large percentage of the Nation's undiscovered oil and gas resources. For this reason, a critical assumption was required concerning the amount of acreage in these areas that would be made available and the time of its availability.

It was assumed that the lease sales schedule announced in 1971 by the Department of the Interior (shown in Table 37) would apply and that there would also be California offshore sales. Since the Department of the Interior's schedule extends only through 1975, an extrapolation was made to cover the remaining 10 years.

The announced schedule did not specify the amount of acreage to be offered for lease at each sale. However, it was assumed that sufficient acreage would be offered to meet the exploration needs projected in these areas. As an example, the offshore exploratory acreage requirements used in Case II for specific years are shown in the following tabulation.

	Thousand Acres per Year
1971	673
1975	1,101
1980	1,663
1985	2,263

During the 15-year period, a total of about 21 million acres would be required. This compares with slightly over 7 million acres that industry leased on the Outer Continental Shelf (OCS) during the 1952-1970 period.

The sensitivity of this critical item is examined in more detail in the parametric studies.

Supply—Oil

Ultimately Discoverable Oil

The NPC's Future Petroleum Provinces report was used to define the discoverable oil-in-place of the United States.* In that report, estimated future discoverable oil was separated into "probable and possible" and "speculative" categories. Only half of the speculative oil was included along with all of the probable and possible for purposes of this study. This represents the "median (expectable) estimate" presented in the Petroleum Provinces study.

Subsequent to publication of the Petroleum Provinces report, its authors were consulted to update the estimates as required and to develop an allocation of the future oil resources between onshore and offshore for the three coastal regions. As a result of recent developments on the North Slope of Alaska, the oil-in-place previously considered speculative is now considered probable and possible. Estimates were also added for speculative oil-in-place for the more prospective portions of the Alaskan Continental Shelf which were not included in the Petroleum Provinces report. Except for the Gulf of Alaska, these Alaskan offshore estimates cannot be considered as discoverable in the near future because of the very hostile operating conditions.

Present estimates are summarized in Table 38. The total discovered and discoverable estimate of 810.4 billion barrels is an increase of 90.6 billion barrels over the 719.8 billion estimated in the Petroleum Provinces report. Taking into account oil-in-place added by discoveries and revisions since the report was written, oil discoverable after 1970 is now estimated to be 385.2 billion barrels—53.3 billion barrels more than estimated in the Petroleum Provinces report. Of this volume, 160.2 billion barrels—42 percent of the oil-in-place remaining to be found—is located in offshore areas.

* NPC, *Future Petroleum Provinces of the United States* (July 1970).

TABLE 37

DEPARTMENT OF THE INTERIOR SCHEDULE OF ANNOUNCED LEASE SALES*

Tentative Schedule—OSC Leasing†

SALES	1971												1972												1973												1974												1975											
	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Gulf of Alaska General													3	4	5			6														THIS SALE, OR ONE OF COMPARABLE POTENTIAL RESERVES, TO BE HELD PRIOR TO 1976																													
Gulf of Mexico Drainage						4		6	7	SALE																																																			
E. Louisiana Gen. & Gulf of Mexico Dr.	1		2				3	4	5	6	7	SALE																																																
Louisiana Gen. & Gulf of Mexico Dr.						1		2	3	4	5		6	7			SALE																																											
E. Texas Gen. & Gulf of Mexico Dr.									1			2		3	4	5		6		7			SALE																																						
Ala., Miss., & Fla. Gen. & Gulf of Mexico Dr.															1			2		3	4	5		6		7			SALE																															
La. & E. Texas Gen. & Gulf of Mexico Dr.																					1			2		3	4	5		6		7			SALE																										
Gulf of Mexico Drainage																																		4		6		7			SALE																			
La. & Texas Gen. & Gulf of Mexico Dr.																																	1			2		3	4	5		6		7			SALE														
Atlantic General																			3		4	5			6						THIS SALE, OR ONE OF COMPARABLE POTENTIAL RESERVES, TO BE HELD PRIOR TO 1976																													
Gulf of Mexico Drainage																																													4		6		7			SALE							
Gulf of Mexico Gen. & Dr.																																												1			2		3	4	5		6		7			SALE	

• "U.S. Will Step Up Offshore Leasing," *Ocean Industry* (July 1971), p. 15.

† Number Code for Tentative Schedule—OCS Leasing: 1—Call for nominations; 2—Nominations due; 3—Hearing notice; 4—First draft of Environmental Quality Statement; 5—Hearing; 6—Environmental Quality Statement; 7—Notice of sale.

Some additional estimates of all ultimately discoverable petroleum liquids originally in place (not just crude oil) have been published. They are shown in Table 39.

To provide more accurate estimates of the results of future finding and developing efforts, an analysis was made of the remaining oil-in-place in each region by geologic horizon and depth.

Oil Finding Rate

Utilizing the results of the resource studies, possible future exploration success rates were established in terms of oil-in-place discovered per foot of exploratory drilling in each region. Since exploratory success varies widely, high and low finding rates were projected for each region.

The technique used to determine regional finding rates was as follows:

- Oil-in-place found per foot of exploratory oil drilling in each region was calculated annually for the period 1956 through 1970. The regional oil-in-place found by the drilling effort in a given year was calculated from the American Petroleum Institute (API) annual reserve additions. This was done by dividing each region's annual reserve additions by the primary recovery factor established for that re-

TABLE 38

OIL-IN-PLACE RESOURCES

		Billion Barrels		Remaining Discoverable Oil-in-Place	
Region		Ultimate Discoverable Oil-in-Place	Oil-in-Place Discovered to 1/1/71	Billion Barrels	% of Ultimate
Lower 48 States—Onshore					
2	Pacific Coast	101.9	80.0	21.9	21.5
3	Western Rocky Mtns.	43.6	5.8	37.8	86.7
4	Eastern Rocky Mtns.	52.4	23.9	28.5	54.3
5	West Texas Area	151.6	106.4	45.2	29.8
6	Western Gulf Coast Basin	109.0	79.7	29.3	26.9
7	Midcontinent	63.0	58.4	4.6	7.3
8–10	Michigan, Eastern Interior and Appalachians	36.5	30.5	6.0	16.4
11	Atlantic Coast	3.8	0.2	3.6	94.7
	Total	**561.8**	**384.9**	**176.9**	**31.5**
Offshore and South Alaska					
1	South Alaska Including Offshore	26.0	2.9	23.1	88.8
2A	Pacific Ocean	49.6	1.9	47.7	96.2
6A	Gulf of Mexico	38.6	11.5	27.1	70.0
11A	Atlantic Ocean	14.4	0.0	14.4	100.0
	Total	**128.6**	**16.3**	**112.3**	**87.3**
Total United States (Ex. North Slope)		**690.4**	**401.2**	**289.2**	**41.9**
Alaskan North Slope					
Onshore		72.1	24.0	48.1	66.7
Offshore		47.9	0.0	47.9	100.0
	Total	**120.0**	**24.0**	**96.0**	**80.0**
Total United States		**810.4**	**425.2**	**385.2**	**47.5**

TABLE 39

ESTIMATES OF ULTIMATELY DISCOVERABLE PETROLEUM LIQUIDS ORIGINALLY IN PLACE*
(Billion Barrels)

	1972 USGS	1969 Hubbert	1959 Weeks	1970 Moore	1968 Elliott and Linden
Lower 48 States	1,519	516	Not Estimated		
Alaska	376	78			
Total United States	**1,895**	**594**	**1,315**	**670**	**1,286**

* P. K. Theobald, S. P. Schweinfurth and D. C. Duncan, *Energy Resources of the United States,* U. S. Geological Survey, Circular No. 650 (July 1972).

gion. The API reserve addition categories of "new fields," "new pools" and "extensions" were used for this purpose since these represent reserves which result from new oil-in-place found. Reserve additions from improved primary recovery and additional recovery projects are reported as "revisions."

- For each region, the historical finding rate was plotted as a function of the cumulative exploratory footage drilled since 1956.
- Trends were established from these plots and were projected into the future using a range of probable rates. A set of lower finding-rate projections was based on a simple semi-logarithmic extrapolation of past trends. Another set of projections was made predicated on the possibility of altering the historical trend through technological improvements, through discovery of some unsuspected "giant" fields (100 MMB or larger), or through additional rewards resulting from increased risk-taking spurred on by improved incentives. These more optimistic trends averaged 50 percent higher than the low cases.

For regions which have no reliable historical data, finding curves were established by assuming similarity with a more mature region. For example, the Atlantic Coast offshore province was assumed to be analogous to the offshore Gulf Coast.

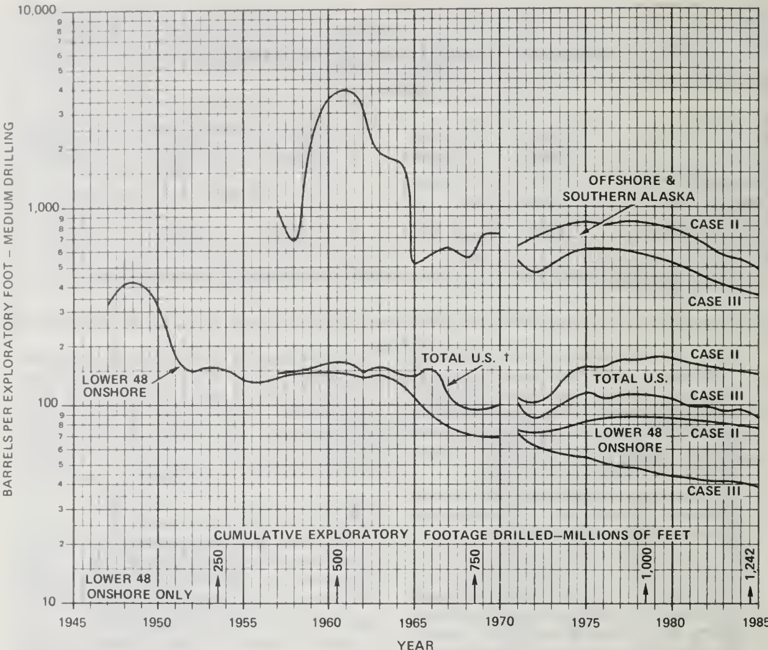
Composite finding trends for the total United States are shown in Figure 8. These composites reflect the changing mix as exploration shifts from the lower 48 states onshore area into the frontier provinces of the offshore areas and Alaska. Since these frontier provinces are still in the early stages of development, their finding rates are projected to remain quite high, while those for the older onshore areas continue to decline.

Oil Drilling Activity

The second parameter that must be considered is exploratory drilling which is expressed in footage drilled per year. It is this activity which discovers the additional oil-in-place that expands the reserve base to support future production levels.

In order to cover the range of possible exploration activities, a spectrum of three U.S. exploration drilling trends was selected for the projection period (see Figure 9). The highest activity level (Case I) assumed a 7.5 percent per year growth rate in exploratory footage. An intermediate activity level (Cases II and III), though still high, assumed a 5 percent per year growth. On the low end of the spectrum (Case IV), a decline in activity of about 3 percent per year was used. All of these trends were assumed to have as their base point the estimated 1971 drilling level.

These exploratory drilling levels for the total United States (excluding North Slope) were distributed by geologic region in accordance with the data on each region's current share of the Nation's drilling effort, future potential and costs. The dis-



* Excluding North Slope.
† 3–Year Running Averages on History

Figure 8. Oil Finding Rates—Medium Drilling.*

tribution used in the analysis is shown in Table 40.

Although exploratory drilling is a key determinant of the oil-in-place that will be discovered in the next 15 years, the total amount of drilling, including development drilling, is important in determining costs of finding and developing oil supplies. The amount of development drilling is related to the assumed exploratory drilling level as a function of the amount of oil found by each exploratory well. If, on an average, exploratory wells find relatively large amounts of oil, more development wells will be required than if exploratory wells find only small reservoirs. In each region a correlation of total drilling to exploratory drilling was derived using data for the last 15 years. These correlations were then used in projecting total drilling as a function of the assumed exploration drilling and success levels. The resulting total oil drilling is shown on Figure 9.

The number of wells resulting from these drilling footages are indicated in Figure 10. As a result of the increasing well depth needed to reach the future oil resources, total wells drilled do not increase as rapidly as the footage drilled.

TABLE 40

PROJECTED REGIONAL ALLOCATION—EXPLORATORY DRILLING EFFORT

Region		Percent of Total U. S. Oil Exploratory Drilling 1970	1975	1980	1985	Initial Appraisal*
1	Alaska†	0.1	0.7	1.0	1.5	0.6
2A	California Offshore	0.5	2.5	3.0	3.0	1.2
6A	Gulf Coast Offshore	2.1	7.0	8.0	9.0	5.8
11A	Atlantic Coast Offshore	–	0.2	0.5	2.0	–
Total Offshore and Alaska		**2.7**	**10.4**	**12.5**	**15.5**	**7.6**
2	Pacific Coast	4.2	4.0	4.0	4.0	5.1
3	Western Rocky Mtns.	6.0	5.0	4.5	5.1	2.0
4	Eastern Rocky Mtns.	28.1	26.5	25.8	24.6	12.9
5	West Texas	14.4	13.5	13.0	12.5	20.0
6	Gulf Coast Onshore	27.8	24.5	23.0	19.6	24.9
7	Midcontinent	14.0	9.7	8.9	8.2	18.9
8–10	Michigan, Eastern Interior and Appalachians	2.3	4.5	5.5	6.5	8.5
11	Atlantic Coast Onshore	0.5	1.9	2.8	4.0	0.1
Total Lower 48 Onshore		**97.3**	**89.6**	**87.5**	**84.5**	**92.4**
Total United States		**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

* Percent of total drilling rather than exploration drilling.

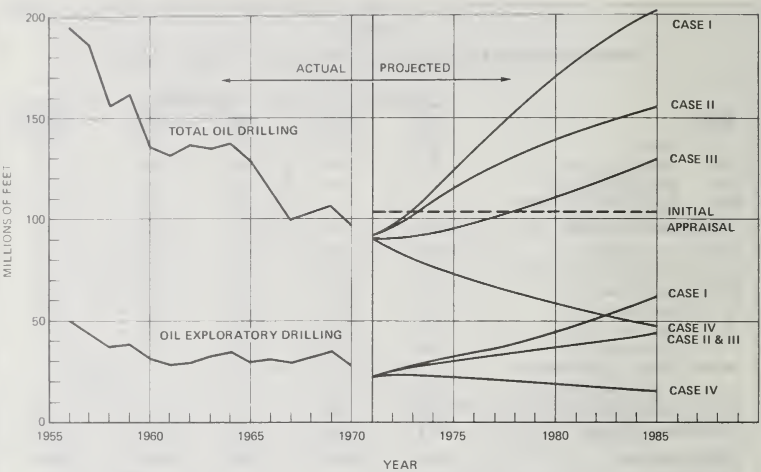
† Excluding North Slope.

Oil-in-Place Found

Once projections of regional oil-in-place finding rates and exploratory drilling rates had been established, the appropriate multiplication of the two resulted in a schedule of oil-in-place found per year by region for the 15-year projection period.

The amount of oil-in-place discovered in the four cases is shown in Figure 11. This plot is a composite U.S. total on a cumulative basis. The lowest discovery case (Case IV) is based on an extrapolation of the drilling and finding rates of the last 15 years. It is also the case which most nearly approximates the findings projected by the Initial Appraisal. Cases I, II and III show various volumes of increase above the declining historical discovery experience because of substantially increased drilling rates and, for Cases I and II, more favorable finding rates. The results of all four cases, as compared to the Initial Appraisal, are presented in Table 41 by geographic region. As indicated, a little over half of the total U.S. ultimate discoverable oil-in-place had been found by 1971. Oil discovered in the 1971-1985 period, with the high and low projections, is summarized in Table 42.

Case I results from the most optimistic level of achievement for all important factors. In order to achieve Case I, it would be necessary to maintain the high drilling growth rate and the high finding rate in each region, each year, for the entire 15-year period. With the North Slope added to these results, 119 billion barrels of oil would be found, which is more than twice as much as the Case IV volume. It would represent an amount equivalent to 30 percent of all the oil found in the United States since the inception of the oil business. Cases II and III fall between Cases I and IV and were used in making more extended studies. The Initial Appraisal results fall between those for Cases III and IV.



* Excluding North Slope drilling

Figure 9. Oil Drilling Rate Projections—Million Feet Drilled.*

In order for the high projections to be met, an enormous amount of exploration will be required in the frontier areas of offshore and Alaska, including the North Slope. For example, Case I projects that 31 percent of the total ultimate oil discoverable in these frontier areas will be found during the next 15 years compared with 16 percent discovered to date. Also, the older onshore areas will be nearing the ultimate discoverable estimates by 1985 as shown in Table 43.

Oil Reserve Additions

The procedure for determining annual oil reserve additions was as follows: Using the regional projections of oil-in-place found per year, primary reserve additions resulting from exploratory effort each year were calculated by applying the regional primary recovery factor to the oil-in-place discovered that year. Reserve additions from application of secondary and tertiary operations originate from both oil-in-place found in prior years and that found during the projection period. Additional reserves from this source were added as a function of length of time since discovery. In each region, the future recovery efficiencies were projected based upon past history, expected reservoir characteristics and related reservoir performance.

The composite U.S. recovery efficiency resulting from application of this methodology was consistent with the trend experienced over the last 15 years, as shown in Figure 12.

In addition to determining crude oil reserve additions in this manner, reserve additions of associated-dissolved natural gas found in the same reservoirs with the oil were estimated. The historical ratios of associated-dissolved gas reserves added per unit of crude oil reserves were applied to the crude reserve additions calculated for each year.

A projection of the total reserve additions resulting from new oil-in-place found and additional recovery efforts on both old and new oil-in-place (excluding the North Slope) is shown in Figure 13. For the last 15 years, the reserve additions from

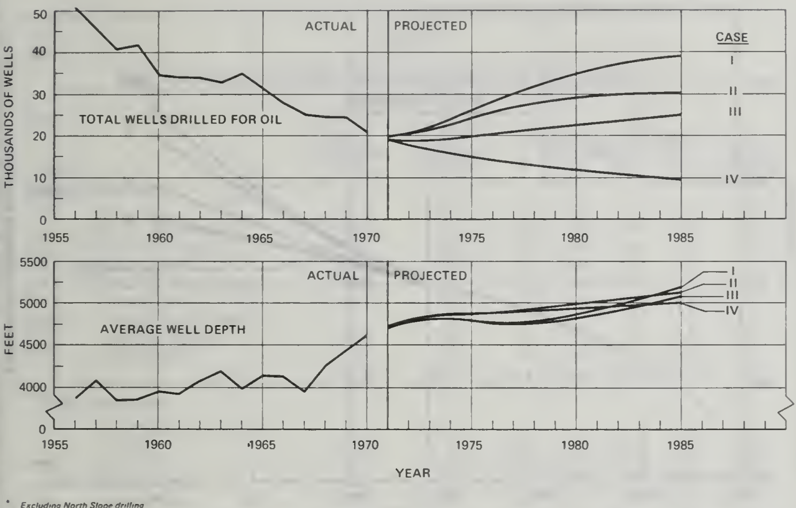


Figure 10. Total Oil Wells Drilled and Average Depth.*

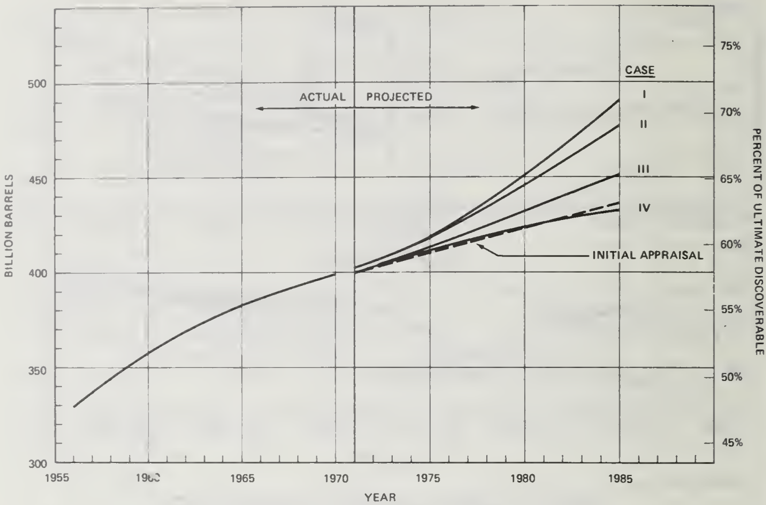
all sources, including revisions, have remained relatively constant at about 2.7 billion barrels per year. Case IV projects annual reserve additions to average about 2.5 billion barrels—about 10 percent below historical levels. The Initial Appraisal showed future reserve additions averaging 2.8 billion barrels per year. Case I reaches a maximum of approximately 4.6 billion barrels per year during the 15-year period and has a yearly average of 3.8 billion barrels. This is 41 percent more than the industry achieved in the last 15 years.

With the North Slope *included* in the comparisons, average annual reserve additions are noted in the following tabulation:

1956-1970	1971-1985 Projected (Billion Barrels)			
	Case			
Actual	I	II	III	IV
3.3	4.4	4.1	3.5	2.9

The reserve additions by region for the 1971-1985 period are summarized and compared with the experience of the previous 15 years in Table 44. This table demonstrates the sizable contribution that will be required from the frontier areas of offshore and Alaska, including the North Slope. For these areas, 1.7 times the reserves booked in the past 15 years are projected for addition during the 1971-1985 period in Case I. Additions for this case in the more mature lower 48 state onshore areas are projected to be 18 percent higher than historical experience, largely as a result of the application of additional recovery processes.

Figure 14 shows a typical distribution of the reserve additions resulting from different recovery mechanisms for one of the intermediate cases (Case II). This demonstrates the significance of the secondary and tertiary recovery projections. Over the last 15 years, the reserve additions resulting from improved recovery efficiency have steadily increased from about 29 percent of the total reserve additions in 1956 to 67 percent in 1970; however, reserve additions resulting from exploration have steadily declined. During this historical period, improved recovery has averaged about 0.9 billion



* *Excluding North Slope operations.*

Figure 11. Cumulative Oil-in-Place Discovered.*

barrels per year, increasing to 2 billion barrels in 1970.

In 1985 for Case II, the contribution of improved recovery processes is about 60 percent of the annual reserve additions in that year. The impact of tertiary recovery processes gradually increases with time so that in 1985 about 25 percent of the total reserves added are provided by new recovery processes. These processes are now in the research and development stage and are not commercially applicable at present prices.

Oil Production

Oil production was scheduled as a function of the reserves remaining at the beginning of each year for each region using fractions for production as a function of reserves. This fraction is the reciprocal of the commonly used reserves/production ratio (R/P). Over the last 10 years, the total U.S. R/P has declined as excess producing capacity was utilized. This trend is shown in Table 45.

Currently, the net excess capacity (excluding the East Texas field and the emergency reserves in Naval Petroleum Reserve No. 1 [NPR-1]) is less than 0.5 MMB/D. Without any significant excess capacity remaining, the declining R/P trend must level off, and the ratio will be approximately constant in the future at the current level.

Projected total U.S. crude oil production, including the North Slope, for the six cases and the Initial Appraisal is shown in Table 46 and Figures 15 and 16.

Over the last 15 years, crude production has increased gradually from about 7 MMB/D in 1956 to 9.1 MMB/D in 1971. Future production for Case IV, in which drilling activity continues its historical downtrend, is projected to decline to 7.6 MMB/D by 1980. North Slope production is

TABLE 41

REGIONAL OIL-IN-PLACE DISCOVERED—TOTAL UNITED STATES
(Billion Barrels)

Region		Ultimate Discoverable OIP	OIP Discovered to 1/1/71	OIP Discovered 1971–1985 Case I	II	III	IV	Initial Appraisal
Lower 48 Onshore								
2	Pacific Coast	101.9	80.0	2.6	2.1	1.7	1.1	3.4
3	Western Rocky Mtns.	43.6	5.8	1.6	1.4	0.8	0.6	1.2
4	Eastern Rocky Mtns.	52.4	23.9	7.9	6.6	2.9	1.9	5.2
5	West Texas Area	151.6	106.4	8.7	6.9	4.6	3.2	2.0
6	Western Gulf Coast Basin	109.0	79.7	11.8	10.4	6.3	4.0	3.1
7	Midcontinent	63.0	58.4	3.9	3.4	2.3	1.5	2.7
8–10	Michigan, Eastern Interior and Appalachians	36.5	30.5	4.9	4.4	2.2	1.5	2.1
11	Atlantic Coast	3.8	0.2	1.0	0.8	0.5	0.3	–
	Total	**561.8**	**384.9**	**42.4**	**36.0**	**21.3**	**14.1**	**19.7**
Offshore and Alaska								
1	Southern Alaska Including Offshore	26.0	2.9	11.6	10.4	6.7	4.6	4.7
2A	Pacific Ocean	49.6	1.9	20.2	17.0	12.6	7.2	3.7
6A	Gulf of Mexico	38.6	11.5	13.6	12.5	8.8	6.1	13.0
11A	Atlantic Ocean	14.4	0	2.2	1.5	1.3	0.5	–
	Total	**128.6**	**16.3**	**47.6**	**41.4**	**29.4**	**18.4**	**21.4**
Total United States (Ex. North Slope)		**690.4**	**401.2**	**90.0**	**77.4**	**50.7**	**32.5**	**41.1**
Alaskan North Slope								
Onshore		72.1	24.0	29.0	23.3	23.3	15.2	0
Offshore		47.9	0	0	0	0	0	0
	Total	**120.0**	**24.0**	**29.0**	**23.3**	**23.3**	**15.2**	**0**
Total United States		**810.4**	**425.2**	**119.0**	**100.7**	**74.0**	**47.7**	**41.1**

initiated in 1981, and the total U.S. rate increases to 9.4 MMB/D by 1985.

The Initial Appraisal assumed that North Slope oil would begin flowing in 1975, but subsequent delays in approval of the pipeline have proved this to be an unrealistic expectation. Initiation of North Slope production for Cases I through III is assumed to occur in 1976. This explains the sharp increase in total U.S. production in that year. The production decline shown in the near future is a result of the inevitable time lag between increasing exploratory activity and realization of the resulting increased production. Once the results of the increased exploratory activity begin to be felt, along with the impact of North Slope startup, U.S. production is projected to increase to 1985 levels of 10.6 to 13.5 MMB/D for these expansion cases. These volumes exceed the Initial Appraisal starting in the late 1970's, even though the Initial Appraisal had the benefit of higher drilling rates in the early 1970's and North Slope production beginning a year earlier.

Figure 17 depicts, for Case II as an example, the components of U.S. crude production by recovery mechanism as well as showing whether or not the reserves were discovered before 1971. A tremendous amount of reserves have already been found on the North Slope. However, some additional oil

TABLE 42

OIL DISCOVERED—1971-1985

	Oil Discovered 1971-1985 (Billion Barrels)	
	Case I	Case IV
United States (ex North Slope)	90.0	32.5
North Slope	29.0	15.2
Total United States	**119.0**	**47.7**

	% of Ultimate OIP Discovered		
		To 1/1/86	
	To 1/1/71	Case I	Case IV
United States (ex North Slope)	58	71	63
North Slope	20	44	33
Total United States	**52**	**67**	**58**

must be found in the future to support 2.0 MMB/D production rate projected for this area. No attempt has been made to split this area between the new and old field categories; rather, it is shown separately to illustrate its impact on production volumes.

Over the last 15 years, production from primary reserves has remained fairly constant at 5.0 to 5.5 MMB/D, while production from fields in which some sort of additional recovery project is underway has grown from about 1.5 to 3.5 MMB/D. Despite declining drilling and reserve additions, no appreciable decline in primary production has been apparent, largely because substantial spare capacity was available during this time period. Now that this spare capacity no longer exists, a normal decline is projected to ensue.

If no new fields were found after 1970, lower 48 states primary production would decline from 5.5 MMB/D in 1970 to about 1.0 MMB/D in 1985—a drop of over 80 percent. Although heavy application of secondary and tertiary recovery processes would mitigate this decline, the current 9.1 MMB/D would still decline by 40 percent to 5.5 MMB/D by the end of the period. By 1985, these additional recovery projects are expected to account for about 80 percent of production from reservoirs discovered before 1971.

Of the total 1985 production rate of 12.2 MMB/D projected for Case II, the North Slope will account for 16 percent, old reserves will contribute 45 percent, and new discoveries made in 1971 and later years must account for 39 percent. The nearly 4.7 MMB/D of production from new discoveries is the equivalent of over two-thirds of the average daily production from 1956 to 1965 for the whole country. Most of these newly discovered reserves will still be producing under primary recovery mechanisms by 1985. However, this new oil will provide the basis for application of current and improved additional recovery techniques. These techniques should have at least as much impact on production from new fields after 1985 as they are projected to have during the next 15 years on currently known reserves.

Figure 18 presents a breakdown of daily production by geographic area for Case II. As shown, lower 48 onshore production just about holds its own throughout the 1971-1985 period. During this same period, production from offshore is projected to almost double. In 1985, for Case II, 61 percent of the total U.S. production will be provided by the onshore areas of the lower 48 states while 39 percent will be provided by offshore and Alaska, including the North Slope. The size of this projected increase in volumes from frontier areas emphasizes the need for making lands available for exploration in these regions.

Figures 19 and 20 demonstrate that the total of petroleum liquids production in 1985 ranges from about 10.4 MMB/D to about 15.5 MMB/D. This amounts to as much as 50 percent more than the supply projected in the Initial Appraisal. However, even in the more optimistic cases, the lead time requirements are such that little improvement is realized until after 1975.

Associated-Dissolved Gas Production

Associated-dissolved gas produced for each of the cases was derived from regional gas/oil ratios based on historical experience. A 13-percent reduction factor for lease use, fuel and losses based on historical data was used to convert associated-dissolved gas production totals to marketed gas volumes.

Supply—Gas

Ultimately Discoverable Gas

The definition of ultimate gas discoverable was

TABLE 43

REGIONAL OIL-IN-PLACE DISCOVERED—TOTAL UNITED STATES
% OF ULTIMATE DISCOVERABLE
(Billion Barrels)

Region		Ultimate Discoverable OIP	% of Ultimate Discovered to 1/1/71	% of Ultimate OIP Discovered to 1/1/86 Case I	II	III	IV
Lower 48 Onshore							
2	Pacific Coast	101.9	79	81	81	80	80
3	Western Rocky Mtns.	43.6	13	17	17	15	15
4	Eastern Rocky Mtns.	52.4	46	60	58	51	49
5	West Texas Area	151.6	70	76	75	73	72
6	Western Gulf Coast Basin	109.0	73	84	83	79	77
7	Midcontinent	63.0	93	99	98	96	95
8–10	Michigan, Eastern Interior and Appalachians	36.5	84	97	96	90	88
11	Atlantic Coast	3.8	5	32	26	18	13
	Total	561.8	69	76	75	72	71
Offshore and Alaska							
1	Southern Alaska Including Offshore	26.0	11	56	51	37	29
2A	Pacific Ocean	49.6	4	45	38	29	18
6A	Gulf of Mexico	38.6	30	65	62	53	46
11A	Atlantic Ocean	14.4	0	15	10	9	3
	Total	128.6	13	50	45	36	27
Total United States (Ex. North Slope)		690.4	58	71	69	65	63
Alaskan North Slope							
Onshore		72.1	33	74	66	66	54
Offshore		47.9	0	0	0	0	0
	Total	120.0	20	44	39	39	33
Total United States		810.4	52	67	65	62	58

derived by combining the volumes of past production and current proved reserves with the Potential Gas Committee (PGC) estimate of the remaining potential supply of natural gas.* The PGC makes an estimate every 2 years of potential gas supply remaining to be discovered. Each revision reflects changes in technology and results of exploration and development that have occurred in the preceding 2 years. Some reallocation was necessary to make the PGC area estimates coincide with NPC regions. All reserves and production volumes reported herein are on the same bases as volumes reported by the American Gas Association (AGA) and the PGC.

As estimated by the PGC, 62 percent of the potential supply of 1,178 TCF of natural gas in the United States, including associated-dissolved, is situated in operationally difficult or frontier areas—approximately 14 percent is below 15,000 feet onshore, 20 percent is offshore and 28 percent is in Alaska.

Associated-dissolved gas potential was estimated by applying historical gas oil ratios to potential oil

* *Potential Supply of Natural Gas in the United States (as of December 31, 1970)*, a Potential Gas Committee report sponsored by Potential Gas Agency, Mineral Resources Institute, Colorado School of Mines Foundation, Inc. (October 1971).

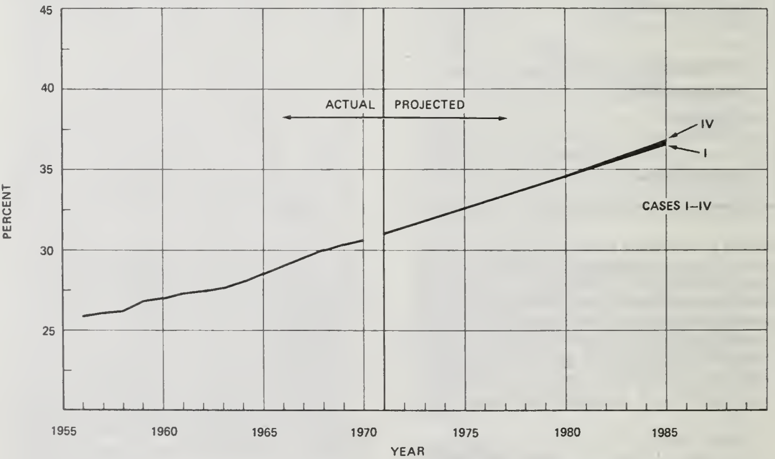
resources. These estimates of associated-dissolved potential gas were subtracted from the PGC estimates to arrive at non-associated potential gas. Table 47 shows non-associated gas potential, previously discovered gas, and ultimate recoverable gas (the sum of potential and discovered) by NPC region. Associated-dissolved gas potential is estimated to be 141.5 TCF, and past discoveries (as of year-end 1970) of associated-dissolved gas amounted to 215.2 TCF. These estimates, when added to ultimate non-associated gas supply of 1,500.6 TCF, result in an estimate of 1,857.3 TCF of ultimate discoverable gas in the United States. Some additional published estimates of ultimately discoverable natural gas originally in place are shown in Table 48.

There is a possibility that utilization of nuclear or other massive fracturing devices might, in the future, recover additional quantities of natural gas from low permeability reservoirs which are not productive in commercial quantities under conventional productive methods. This possibility has not been reflected in PGC estimates of potential supply.

Finding Rates for Non-Associated Gas

The AGA annual estimates of reserve additions in the lower 48 states provided the data used for developing the two finding rates. The AGA's published data for years prior to 1966 does not show non-associated gas reserve additions separately from associated-dissolved gas. Therefore, an allocation was made for these earlier years using U.S. Bureau of Mines production data in conjunction with the published AGA data to arrive at regional non-associated gas reserve additions.

Annual finding rates for non-associated natural gas have fluctuated widely in the past, ranging from 140 MCF to 408 MCF per foot drilled since 1955. Two different statistical methods of analyzing these data were employed to arrive at the projected high and low finding rates. One method was to fit a "growth curve" to the historical relationship between cumulative gas reserves found and cumulative gas footage drilled since 1955 for each region. This statistical treatment resulted in



* *Excluding North Slope operations.*

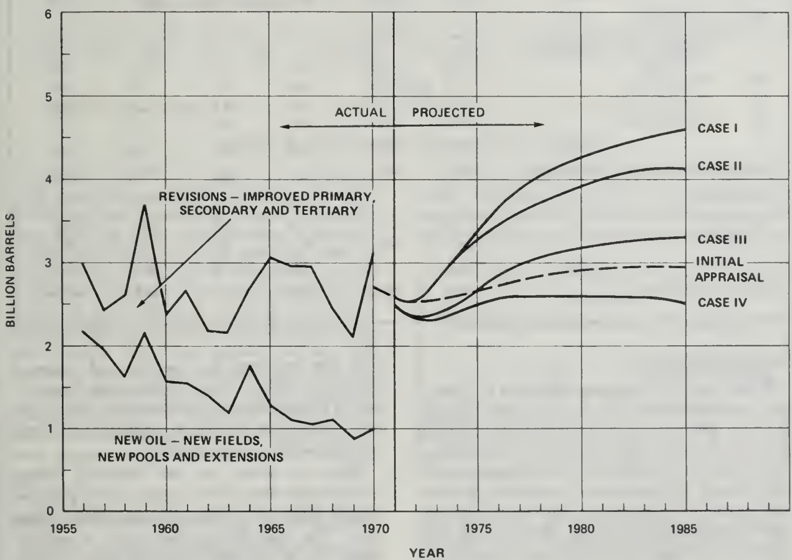
Figure 12. Cumulative Oil Recovery Efficiency (Percent of Oil-in-Place).*

a U.S. gas finding rate, designated the "high finding rate" (Cases I, II and IVA). During the period 1971-1985, this rate is projected to reach a high point of about 350 MCF per foot drilled, and in Case I this rate ultimately drops to approximately 265 MCF per foot drilled.

The "low finding rate" (Cases IA, III and IV) for non-associated gas per foot of hole drilled was estimated regionally by fitting a modified exponential curve to historical data, using the method of least squares. This was statistically applied to the historical relationship between the annual amount of non-associated gas found per foot of hole drilled and cumulative footage drilled for gas during the 15-year period 1956-1970. During the 1971-1985 period, this rate is projected to reach a high of about 240 MCF per foot drilled and to decline gradually to slightly below 200 MCF per foot drilled in Case IA.

In all cases, both the high and low finding rates experience a decline during the 15-year period 1971-1985. The reason is that both statistical systems are properly reflecting the declining probability of maintaining these rates at a constant level as the volume of *remaining* potential reserves to be found decreases.

The average finding rate for the lower 48 states is the weighted average of the projected regional finding rates. Figure 21 shows the average finding rate for the lower 48 states plotted against cumulative footage since 1946 as well as the projected high and low finding rates. The figure shows that the projected finding rates compare favorably with the range and trend of finding rates experienced since 1946.



* *Excluding North Slope reserve additions.*

Figure 13. Oil Reserve Additions.*

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TABLE 44

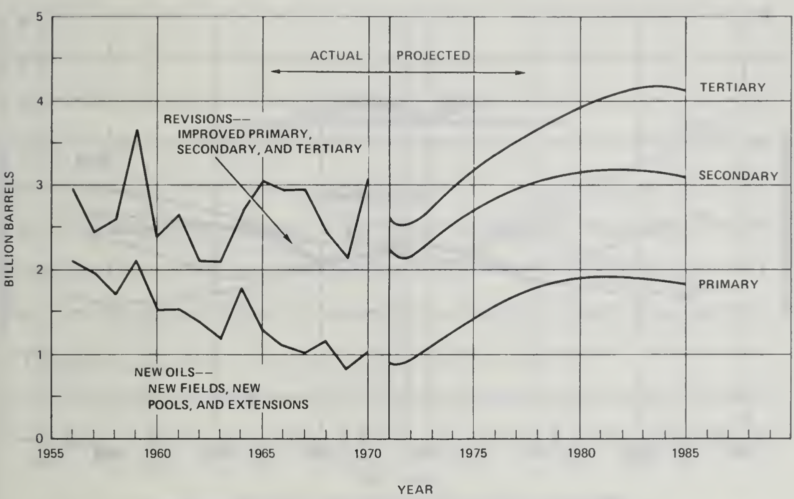
REGIONAL CRUDE OIL RESERVE ADDITIONS–TOTAL UNITED STATES
(Billion Barrels)

Region		Reserves Added 1956–1970	Reserves Added 1971–1985 Case I	II	III	IV	Initial Appraisal
Lower 48 Onshore							
2	Pacific Coast	4.8	4.6	4.5	4.4	4.2	5.1
3	Western Rocky Mtns.	1.1	0.6	0.6	0.4	0.4	0.5
4	Eastern Rocky Mtns.	2.9	3.1	2.7	1.6	1.3	2.4
5	West Texas Area	10.7	10.5	10.1	9.6	9.1	8.9
6	Western Gulf Coast Basin	9.2	15.2	14.5	12.6	11.5	11.0
7	Midcontinent	4.0	3.8	3.7	3.3	3.0	3.4
8–10	Michigan, Eastern Interior and Appalachians	1.4	2.3	2.2	1.4	1.2	1.3
11	Atlantic Coast	0.1	0.3	0.3	0.2	0.1	0
	Total	34.2	40.4	38.6	33.5	30.8	32.6
Offshore and Alaska							
1	Southern Alaska Including Offshore	0.9	3.8	3.4	2.4	1.7	1.7
2A	Pacific Ocean	0.3	4.9	4.2	3.1	1.8	1.0
6A	Gulf of Mexico	5.0	7.0	6.4	4.6	3.3	6.6
11A	Atlantic Ocean	0	0.7	0.5	0.4	0.2	0
	Total	6.2	16.4	14.5	10.5	7.0	9.3
Total United States (Ex. North Slope)		40.4	56.8	53.1	44.0	37.8	41.9
North Slope							
Onshore		9.6	9.7	7.8	7.8	5.1	0
Offshore		0	0	0	0	0	0
	Total	9.6	9.7	7.8	7.8	5.1	0
Total United States		50.0	66.5	60.9	51.8	42.9	41.9

Gas Drilling Activity

Three rates of drilling were projected to encompass a reasonable range of variation in this activity. The high drilling rate (Cases I and IA) assumed that 1971 footage would increase by a 5.4-percent annual average increase over the 15-year period. High growth drilling increases 5 percent the first year, reaching 9 percent in 1980 by 0.5-percent annual increments, and tapers off to a level rate by 1985. The medium drilling rate (Cases II and III) assumes a 3.0-percent annual average over the 15-year period; it follows the same pattern as the high rate but starts at 2 percent and reaches 5 percent in 1980. The low drilling rate (Cases IV and IVA) assumed that the 4-percent average annual decrease in drilling experienced from 1961 to 1970 would continue to 1985.

Figure 22 shows the total allocated footage drilled for gas from 1956 to 1970 and the projected footage for 1971 to 1985 for the three drilling rates. The high drilling rate results in approximately 88 million feet of gas drilling in 1985, compared to the past peak year of 1961 when gas drilling amounted to about 62 million feet.



* Excluding North Slope Reserve Additions

Figure 14. Oil Reserve Additions (Case II).*

The projected number of productive gas wells in 1985 in Cases I and IA total about the same as those drilled in 1961—approximately 6,000 wells in both years (see Figure 23), reflecting that the industry will have to drill to increasingly greater depths in the future and that the average depth of productive gas wells will continue to increase. Average depth of productive gas wells increases approximately 1,700 feet between actual 1970 experience and the projection made for 1985.

Figure 24 shows the increase in actual well depth experienced during the 1956-1970 period and the projection of increasing average well depth through 1985, which is a continuation of the historical trend.

Regional Distribution of Gas Drilling Effort

One of the important judgments required is the regional distribution of gas drilling effort, i.e., the amount of footage drilled for gas in each region for each year for the 1971-1985 period. The three major considerations used in arriving at these projections were the gas potential remaining to be found in each region, the historical trends of gas reserves found per foot drilled in each region, and the historical drilling distribution among the regions.

TABLE 45

PRODUCTION AS A FUNCTION OF RESERVES

	R/P	Production as % of Remaining Reserves
1955	12.2	8.2
1960	12.8	7.8
1965	11.5	8 7
1970	8.9	11.2

The projection of regional drilling distribution for the 1971-1985 period, along with the actual

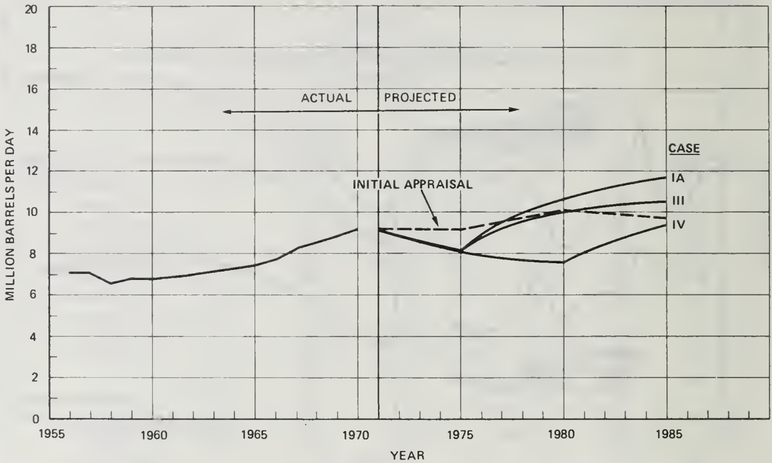


Figure 15. U.S. Crude Oil Production—Low Finding Rate.

distribution for the 3-year period 1968-1970, is shown in Table 49.

Gas Reserve Additions

Natural gas reserve additions projected for the lower 48 states in the case studies, along with the gas footage drilled, are shown in Figures 25, 26 and 27. Figure 28 shows historical annual gas reserve additions and projections for the lower 48 states. Figure 29 shows the cumulative gas discovered through 1970 and the projected cumulative gas discovered for the four principal cases; it shows both absolute volumes and percentages of ultimate discoverable gas. Both non-associated and associated-dissolved additions are included.

During the 1956-1970 period, total gas reserve additions averaged slightly less than 18 TCF per year in the lower 48 states. The peak year in gas reserve additions for all past history was 1956 when nearly 25 TCF were added. During the 3-year period 1968-1970, reserve additions averaged only about 11 TCF per year. In the lowest supply case postulated (Case IV), gas reserve additions are projected to decline from about 11 TCF in 1970 to about 6 TCF in 1985. In the highest supply case (Case I), gas reserve additions are projected to increase to about 26 TCF in 1985.

A little over 31 TCF of gas have been discovered in Alaska, of which 26 TCF of associated-dissolved gas were booked on the North Slope in 1970. Estimated annual average non-associated and associated-dissolved gas reserve additions in Alaska for the 15-year period 1971-1985 are tabulated below.

Case I	4.2 TCF/year
Case II	3.3 TCF/year
Case III	2.4 TCF/year
Case IV	1.3 TCF/year

Table 50 shows by region the cumulative non-associated gas reserve additions projected in the various cases studied. This table also shows the historical non-associated gas reserve additions by region. Table 47, which includes Alaska, shows that 464.1 TCF of non-associated gas had been discovered prior to 1971. This is 30.9 percent of

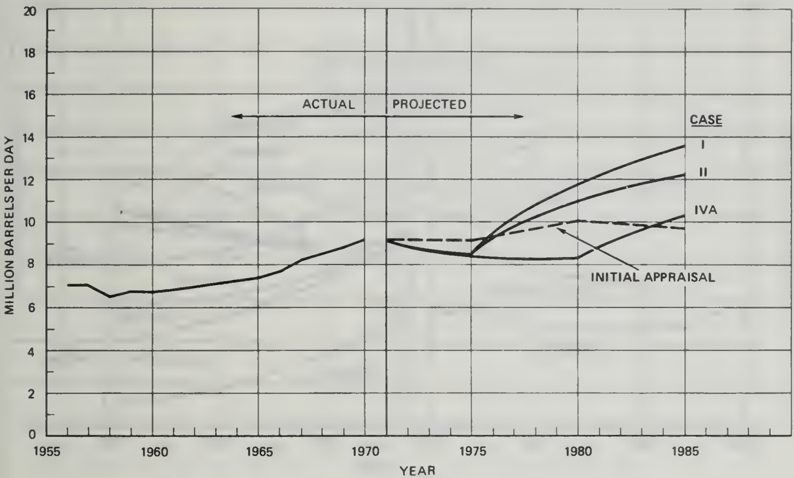


Figure 16. U.S. Crude Oil Production—High Finding Rate.

the estimated ultimate supply of non-associated gas. In the highest supply case (Case I), an additional 358.8 TCF are projected to be discovered in the 1971-1985 period. This would indicate that 54.8 percent of the ultimate non-associated gas supply would be discovered by the end of 1985.

In the lowest supply case (Case IV), a total of 120.1 TCF of non-associated gas reserves are added in the 1971-1985 period, meaning that 38.9 percent of the ultimate would be discovered by the end of 1985.

Table 51 shows regionally the percent of ulti-

TABLE 46

DAILY CRUDE OIL PRODUCTION—TOTAL UNITED STATES (MMB/D)

	Initial Appraisal	Case					
		I	IA	II	III	IVA	IV
1971	9.10	9.10	9.10	9.10	9.10	9.10	9.10
1975	9.15	8.52	8.17	8.48	8.14	8.33	8.04
1980	10.10	11.76	10.58	11.22	10.16	8.28	7.58
1985	9.87	13.54	11.64	12.19	10.55	10.33	9.38

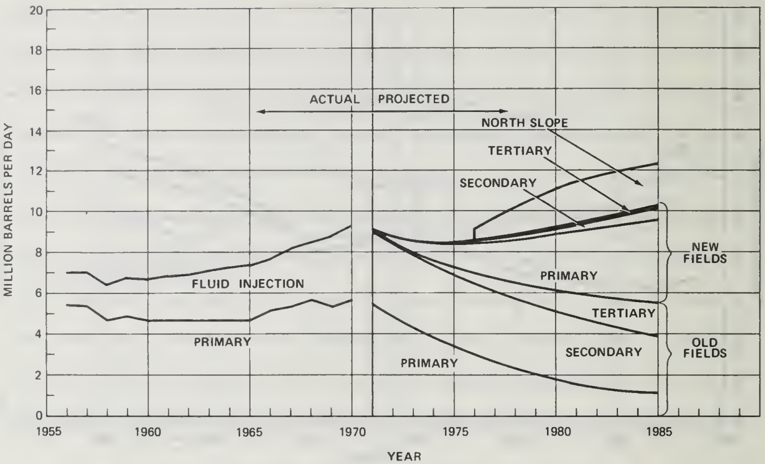


Figure 17. Daily Crude Oil Production (Case II)—Total United States.

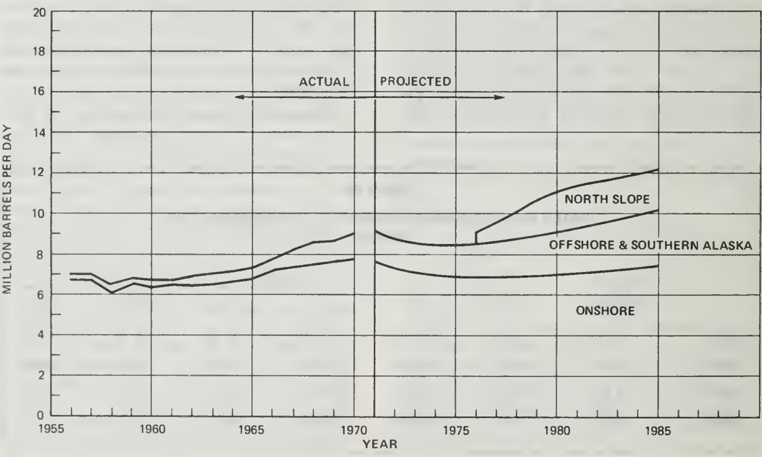


Figure 18. Daily Crude Oil Production (Case II)—Total United States.

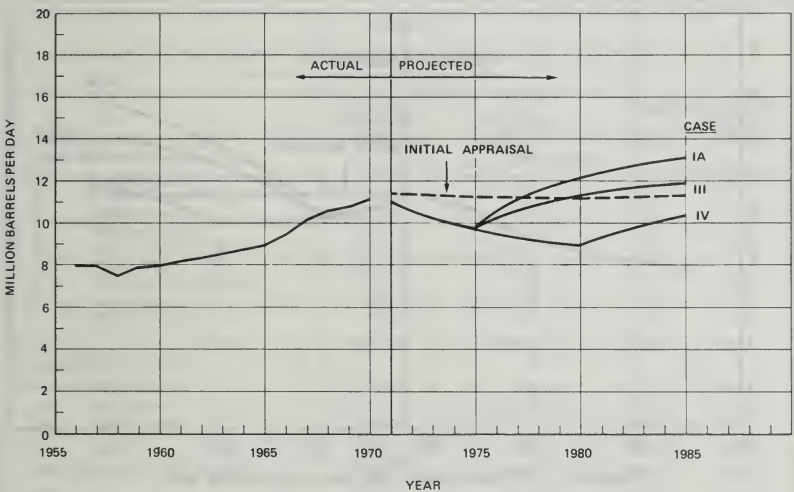


Figure 19. U.S. Total Liquids Production—Low Finding Rate.

mate non-associated gas reserves discovered at the end of 1970 and the percent of ultimate which would be found by the end of 1985 in each of the cases studied.

Gas Production

For the purpose of developing non-associated gas production schedules for each region, percentage/production schedules were established for both proved reserves as of December 31, 1970, and for projected future reserve additions. Each of the schedules was expressed in annual percentages of the particular reserve category involved.

Historical deliverability characteristics applicable to each of the regions were employed in developing these schedules. The availability of gas is principally a function of reservoir characteristics. The average deliverability characteristics of all wells in the lower 48 states were arrived at by analysis of data reported to the FPC on Form 15 reports filed by the interstate pipelines. Based on further regional investigation, availability characteristics for Regions 5, 7 and 11 were assumed to conform to the above average; Regions 3, 4, 8, 9 and 10 were assumed to have 80 percent of the average availability capacity; and Regions 2, 2A, 6 and 6A, and the North Slope were assumed to have 125 percent of the average. Southern Alaska was assumed to produce 4 percent of remaining reserves each year, and the eastern offshore (11A) was assumed to produce 5 percent of the remaining reserves each year. Regional production volumes were summed to obtain total production. A 6.5-percent reduction factor for lease use and fuel, based on historical data, was applied to these production volumes to arrive at marketed non-associated gas production.

Table 52 shows 1970 wellhead production and year-end proved reserves of non-associated gas for the lower 48 states. Figure 30 shows actual wellhead production of non-associated and associated-dissolved gas for the period 1955-1970 for the total United States and projected production for the four primary cases studied. Figure 30 also shows the effect that finding rates have on projected production by comparing Cases II and III. Projected pro-

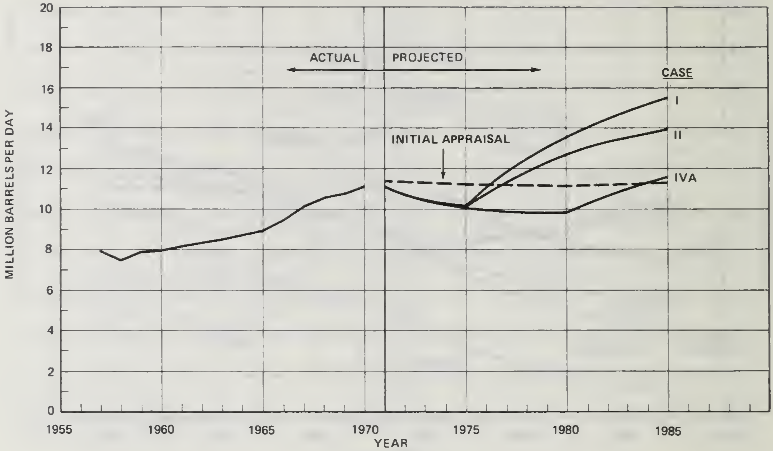


Figure 20. U.S. Total Liquids Production—High Finding Rate.

duction for Case II, which utilizes the high finding rate, is 26.5 TCF annually in 1985. Projected production for Case III, which assumes the same drilling activity as Case II but utilizes the low finding rate, is only 20.4 TCF annually in 1985—a difference of about 6 TCF.

The rapid growth in gas production in the 1960's was a response to the rapid growth in demand. This growth reflected the desirability of gas as a fuel, the large backlog of proved reserves, and FPC pricing policies which held gas prices far below their competitive level in the marketplace. Although demand will continue to grow, there is no longer a backlog of proved reserves to support the approximately 6-percent annual average rate of increase in production achieved in the 1960's. Further increases in gas production will depend on reserve additions made in the future.

Marketed Gas Production

Marketed production volumes are arrived at by reducing non-associated and associated-dissolved wellhead production by factors of 6 percent and 13 percent, respectively. These reductions, which cover lease use, fuel use and losses, are based on historical data.

Table 53 shows, by region, the projected cumulative marketed gas production during the 1971-1985 period for all the cases studied, ranging from approximately 263 TCF (Case IV) to 353 TCF (Case I). Figure 31 shows marketed gas for the United States projected in the cases utilizing the high finding rate (Cases I, II and IVA). Figure 32 shows the marketed gas for the United States projected in the cases utilizing the low finding rate (Cases IA, III and IV).

Natural Gas Liquids (NGL)

Natural gas liquids are produced with both non-associated and associated-dissolved gas. Liquid gas ratios for both reserve additions and production were calculated by region on the basis of historical data. These calculations were made separately for non-associated and associated-dissolved gas. The ratios derived were then applied to projected gas reserve additions and resulting gas production to determine NGL reserve additions and production. The liquids were subdivided on the basis of recent

TABLE 47

RECOVERABLE GAS SUPPLY

Region		TCF: Ultimate Discoverable Gas	TCF: Gas Discovered to 1/1/71	Remaining Discoverable: TCF	Remaining Discoverable: % of Ultimate
Lower 48 States—Onshore		Non-Associated			
2	Pacific Coast	25.7	8.1	17.6	68.5
3	Western Rocky Mtns.	50.1	17.9	32.2	64.3
4	Eastern Rocky Mtns.	51.6	10.0	41.6	80.6
5	West Texas Area	101.5	27.2	74.3	73.2
6	Western Gulf Coast Basin	397.9	211.7	186.2	46.8
7	Midcontinent	223.3	104.8	118.5	53.1
8–9	Michigan, Eastern Interior	12.5	0.4	12.1	96.8
10	Appalachians	95.9	33.0	62.9	65.6
11	Atlantic Coast	4.6	0.01	4.6	99.8
	Total	963.1	413.1	550.0	57.1
Lower 48 States—Offshore					
2A	Pacific Ocean	3.8	0.5	3.3	86.8
6A	Gulf of Mexico	201.8	45.4	156.4	77.5
11A	Atlantic Ocean	54.5	–	54.5	100.0
	Total	260.1	45.9	214.2	82.4
Total United States (Ex. Alaska)		1,223.2	459.0	764.2	62.5
Alaska		277.4	5.1	272.3	98.2
Total United States		1,500.6	464.1	1,036.5	69.1
		Associated-Dissolved			
Total United States		356.7	215.2	141.5	39.7
		Non-Associated and Associated Dissolved			
Total United States		1,857.3	679.3	1,178.0	63.4

historical production into condensate, pentanes and heavier, and LPG.

Table 54 summarizes the annual NGL reserve additions, and Table 55 summarizes daily NGL production in the lower 48 states. In 1985, reserve additions range from about 149 MMB (Case IV) to 692 MMB (Case I), and daily production ranges from 997 to 1,921 MB/D for Cases IV and I, respectively.

Supplemental Supply

Supplemental supplies of gas result from coal gasification, the manufacture of substitute natural gas from liquid feedstocks, and the application of nuclear-explosive technology. Coal gasification is examined in Chapter Five. Discussion of SNG and nuclear-explosive stimulation follows.

Substitute Natural Gas

The shortage of natural gas that will be experienced over the next few years, as well as the long lead times required for large-scale LNG projects and coal gasification plants, has forced gas suppliers and distributors to look for an interim source of supply which could be made readily available. This interim supply source will likely be synthetic pipeline gas formed from petroleum liquids. Industry interest in SNG is evidenced by the fact that close to 40 projects have been announced

TABLE 48

ESTIMATES OF NON-ASSOCIATED AND ASSOCIATED-DISSOLVED GAS*
(TCF)

	1970 PGC	1972 USGS	1969 Hubbert	1959 Weeks	1970 Moore	1968 Elliott and Linden
Lower 48 States	1,877	3,556	1,312	Not Estimated		
Alaska	447	862	188			
Total United States	2,324	4,418	1,500	1,250	1,934	2,175

* P K Theobald, S. P Schweinfurth and D. C. Duncan, *Energy Resources of the United States,* U. S. Geological Survey, Circular No. 650 (July 1972).

having a designed output of over 2.5 TCF of reformer gas per year.

Processes to produce SNG from petroleum liquids have been available for some time. Those currently receiving the most attention are the Catalytic Rich Gas (CRG) process, which was developed by the Gas Council of the United Kingdom; the Methane Rich Gas (MRG) process, developed by the Japan Gasoline Company; and the Lurgi Gasynthan process, which was developed by the Lurgi Company of Germany. These processes, for the most part, use low-temperature catalytic steam. The feedstocks used are naphtha, other lighter hydrocarbons, or methanol. The output will be gas of 1,000-BTU quality which has been upgraded through methanation and carbon dioxide removal. The process operates at 93- to 95-percent thermal efficiency, assuming a naphtha feedstock with a heating value of 5 million BTU's per barrel.

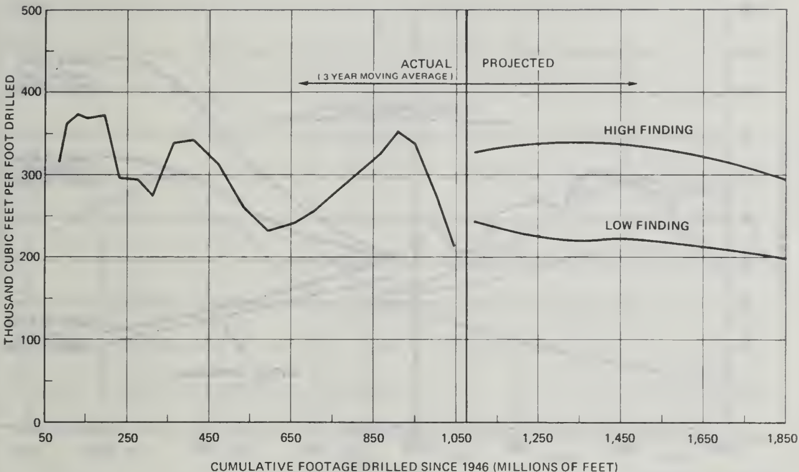
Most of the plant capacities announced assume construction in modules with total capacities ranging from 100 to 500 MCF per day. All plant components, with the exception of catalysts in some cases, are available in the United States. As a general rule, each 100 million cubic feet (MMCF) of plant output will require a raw material input of about 20 to 25 thousand barrels of hydrocarbon feedstock.

Each trillion cubic feet of SNG output will require plant expenditures of approximately $800 million to $1 billion, representing a tailgate cost of some $0.20 to $0.30 per MCF. Feedstock costs represent at least 70 percent of the total. Announced project prices range from $1.00 to $1.60 per MCF.

Construction companies licensed to build such plants are willing to begin construction immediately, contracting for completion on a turn-key basis in less than 2 years. In practice, this relatively short lead time could prove illusory unless the following two principal conditions are satisfied:

- Feedstock Requirements—Feedstock requirements for the SNG plants announced to date amount to approximately 1 MMB/D of light hydrocarbons, a volume that could represent about 20 percent of refinery capacity. In turn, the crude oil that would have to be dedicated to provide reforming feedstock would total about 6 MMB/D, or about 10 percent of world petroleum demand at this time. Considering the known requirements of the petrochemical industry, it appears doubtful that light hydrocarbons in such quantities will be available for reforming.
- Governmental Considerations—Two forms of federal policy administration could present obstacles to SNG projects. These are the regulatory considerations exercised by the FPC and the import philosophy of the Department of the Interior.

The regulatory considerations will relate to the willingness of the FPC to certificate higher cost gas supplies and to resolve such issues as whether higher depreciation rates and high-



* *Excluding Alaskan gas.*

Figure 21. Non-Associated Gas Finding Rates.*

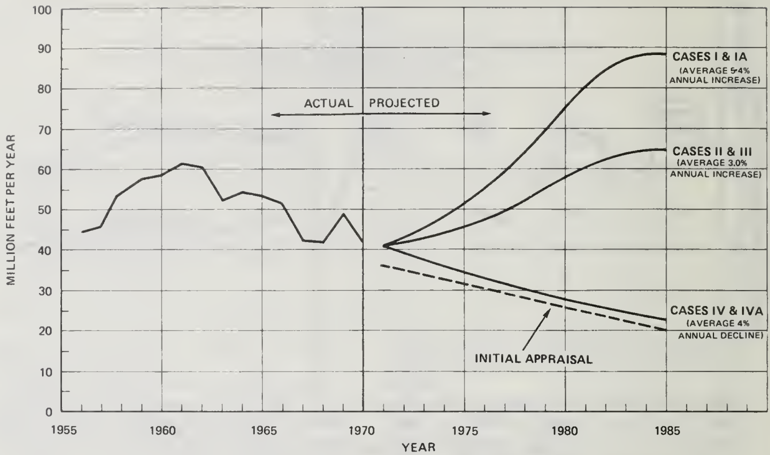
er rates of return on equity than are normally provided for in utility-type construction are appropriate for such innovative activities.

The import question concerns the willingness of the Department of the Interior to permit the import of light hydrocarbons. Approximately two-thirds of the light hydrocarbon feedstock required for these plants is anticipated to be foreign in nature. This has the effect of "exporting" refinery capacity to foreign countries, a concept opposed by the Department of the Interior. To offset such a possible trend, governmental consideration is being given to establishing the Imported Crude Oil Processing (ICOP) plan, described in the oil import section of Chapter Thirteen. This is a plan designed to increase incentive to construct domestic refinery capacity to process imported foreign crude oil. Implementation of this plan could increase the availability of naphtha to be used as feedstock for reformer gas.

The potentially inhibiting effects of regulations and import restrictions and the delays often occasioned by siting difficulties and related administrative-procedural details can, and do, affect timing. Therefore, it has been assumed that only one-third of the announced plants to be in operation by 1975 and one-half of the plants scheduled to be in production in 1980 and 1985 would be completed on a timely basis. Under that assumption, SNG production is estimated at 0.6 TCF in 1975, increasing to 1.3 TCF by 1980 and remaining at that level through 1985.

Nuclear-Explosive Stimulation

Nuclear stimulation of natural gas reservoirs is a method of producing natural gas from tight reservoirs in major basins of the Rocky Mountain area (see Figure 5) where deliverability from conventional wells does not warrant pipeline connections. Approximately 250,000 acres of leased lands have been grouped into three unit areas for the purpose of conducting such operations, and several



* *Excluding Alaskan gas drilling.*

Figure 22. Gas Footage Drilled.*

hundred thousand acres leased outside these units are also believed to have potential for such purposes. It is estimated that there are about 90 TCF of gas in place in such reservoirs currently under lease and that the potential resource base considered appropriate for nuclear stimulation may prove to be much larger.

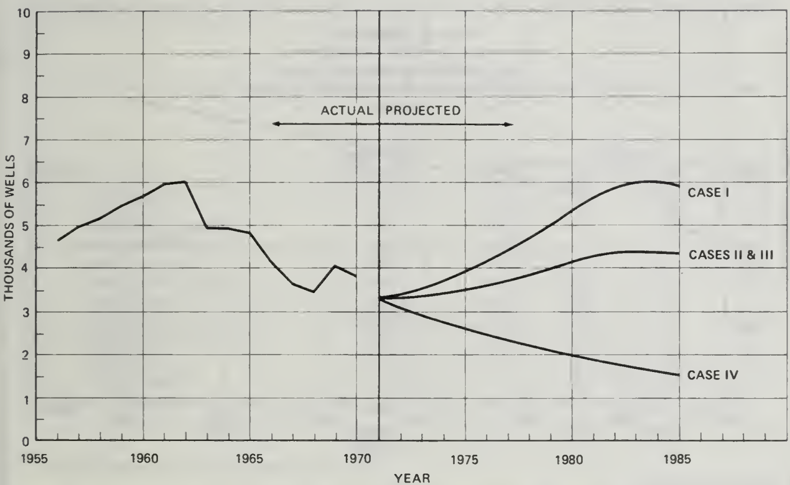
Technical feasibility has been established by the Gasbuggy experiment in northwest New Mexico and the Rulison experiment in Colorado. Two projects (Rio Blanco in Colorado, Wagon Wheel in Wyoming) have been designed which are expected to demonstrate production of about 20 billion cubic feet per well over a 20-year period.

The largest uncertainty in predicting potential future production from a well is establishing formation permeability and the increases in permeability resulting from stimulation. Test results from Gasbuggy and Rulison projects have been extended to other reservoirs by computer modeling and knowledge of formation properties. These results showed, generally, high flow rates during early production decreasing to relatively constant flow rates after about 5 years and a production span that may extend considerably longer than conventionally completed wells.

Assuming favorable results from currently planned experiments and timely resolution of policy issues, estimated annual production in 1980 of 0.1 TCF (Cases II and III) to 0.2 TCF (Case I) may increase to about 0.8 TCF and 1.3 TCF, respectively, in 1985. The corresponding levels of cumulative production for the 1971-1985 period are approximately 2.4 TCF (Cases II and III) and 4.6 TCF (Case I).

These production volumes rest upon activity level assumptions of completion of 676 wells by 1985 in Case I, compared to 500 completed wells in Cases II and III. In Case I, 160 such wells are completed in 1985; in Cases II and III the total is 100. Commercial nuclear stimulation activity does not occur by 1985 under Case IV assumptions, although continued experimentation and technology refinement may be proceeding.

Policy issues relating to availability and cost of nuclear explosives, distribution of natural gas con-



* *Excluding Alaskan gas wells.*

Figure 23. Productive Gas Wells Annually.*

taining small amounts of radioactivity, and wellhead price must be resolved before definitive economic analysis can be performed. However, indications are that the range of prices for such production may compare quite favorably to those for coal gasification, imported LNG, SNG and pipeline imports from Arctic areas.

Alaska

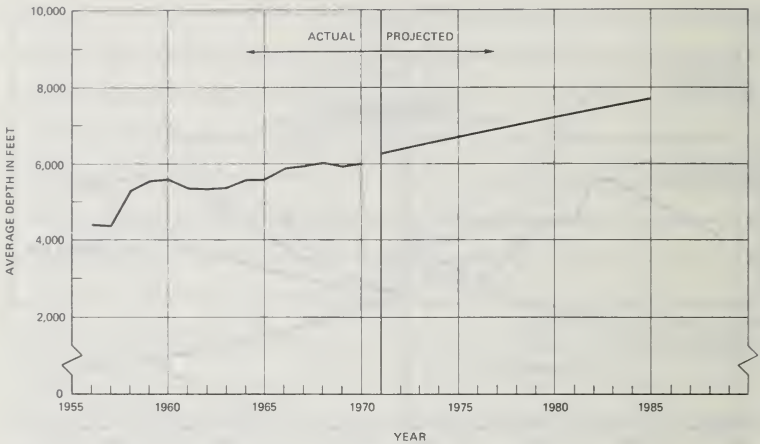
The importance of Alaska and its offshore waters to the Nation's future petroleum supplies is based on the estimate that about 30 percent of the remaining domestic discoverable hydrocarbon resources are located in this area. This amounts to 119 billion barrels of oil-in-place and 327 TCF of recoverable gas. Over 80 percent of this oil and about 52 percent of this gas are believed to be located on the North Slope (north of the Brooks Mountain Range). Figure 33 is a map of Alaska showing the pertinent features and locations.

Southern Alaska

Currently, all of Alaska's production comes from southern Alaska. The area was opened up in 1957 with the discovery of the Swanson River Field (ultimate recovery of about 176 MMB). The most important fields have been discovered on the Kenai Peninsula and offshore in the Cook Inlet. At present these fields are estimated to have ultimate recovery of about 900 MMB and remaining oil reserves of 500 MMB, together with about 5 TCF of remaining gas reserves. Operations in the Cook Inlet, with its icy waters and high tides, are very costly. Such conditions are even more extreme in the Gulf of Alaska, and therefore this should prove to be an even more expensive area of operations.

North Slope

Exploration activity in northern Alaska began in 1944 on Naval Petroleum Reserve No. 4 (NPR #4) under Naval supervision. This work, together with



* *Excluding Alaskan gas drilling*

Figure 24. Average Depth of Completed Gas Wells.*

detailed mapping by the U.S. Geological Survey, continued until 1953. During this 8- to 9-year period three oil fields and two gas fields were discovered. The reserve estimates for these discoveries range from 30 to 100 MMB of oil and 370 to 900 billion cubic feet of gas.

Private industry exploration started in the late 1950's in the area between NPR #4 and the Arctic Wildlife Refuge. NPR #4 and the Arctic Wildlife Refuge together constitute a major portion of the land on the North Slope, and neither of these is currently available for exploration by the industry. These efforts resulted in the discovery of the Prudhoe Bay Field in 1968. This field, which appears to be by far the largest oil field ever discovered on the North American Continent, is estimated to contain 24 billion barrels of proved oil-in-place, with proved recoverable reserves of 9.6 billion barrels of oil and 26 TCF of associated-dissolved gas.

The main reservoir in the Prudhoe Bay Field is in the Triassic (Sadlerochit) interval which contains all the field's currently booked reserves. Other productive tests have been made in the Mississippian (Lisburne) and the Lower Cretaceous (Kuparuk) zones in the same field. There are other discoveries in Cretaceous sands at other fields outside the Prudhoe Bay Field (Ugnu, East Ugnu and West Sag River). Finds of the apparent magnitude of these discoveries outside the Sadlerochit reservoir would be of major significance in the lower 48 states, but the operating conditions on the North Slope and high costs involved may render them economically marginal.

Extreme cold, stormy and icy seas offshore, permafrost areas on land, and the limited drilling season make exploration and production operations extraordinarily costly and difficult. For example, Joint Association Survey data for 1968-1970 estimate average costs of drilling wells to depths of 10,000 to 14,999 feet at $1,869,000 in Alaska, compared to $598,000 for the offshore and $251,000

TABLE 49

REGIONAL PROPORTION OF GAS
DRILLING FOOTAGE IN UNITED STATES*
(Percent)

Region*		1968–1970 Average	Projections 1971	1975	1980	1985
2	Pacific Coast	1.97	2.0	2.0	2.0	2.0
2A	Pacific Ocean	0.01	0.1	0.1	0.2	0.3
3	Western Rocky Mtns.	3.93	4.9	5.0	5.1	5.1
4	Eastern Rocky Mtns.	3.72	4.2	4.7	5.7	6.2
5	West Texas Area	8.82	9.6	10.1	10.2	10.6
6	Western Gulf Coast Basin	40.46	40.5	38.3	34.4	31.2
6A	Gulf of Mexico	9.11	10.0	10.6	11.0	11.8
7	Midcontinent	16.95	15.0	15.3	15.6	15.8
8–9	Michigan, Eastern Interior	0.88	0.7	0.7	0.7	0.7
10	Appalachians	13.90	13.0	13.0	12.6	12.8
11	Atlantic Coast	0.03	–	0.1	0.5	1.0
11A	Atlantic Ocean	–	–	0.1	2.0	2.5
Alaska*		0.22	*	*	*	*
	Total	100.00	100.0	100.0	100.0	100.0

* Alaskan footage handled outside computer program.

for the onshore of the lower 48 states.* North Slope costs are even higher than the Alaskan average.

The offshore area of the North Slope is estimated to contain about 48 billion barrels of oil-in-place. Large potential exists for natural gas accumulations offshore, but it has not been quantified separately. However, because of the enormous costs that would be required and the time needed to fully develop the required technology to conduct operations under these conditions, this study does not contemplate that any of this potential will be developed during the next 15 years. Two of the greatest obstacles are ice floes and polar pack movements that often scour the sea bottoms and move in to impinge on the coast.

Alaskan Pipeline

After the discovery at Prudhoe Bay, plans were made for the transportation of the oil to southern Alaska via an 800 mile, 48-inch pipeline. The pipe was ordered and delivered, and initial crude movement through the system was scheduled for 1973. However, governmental and environmental considerations have postponed this date to at least 1976. To date, the industry has invested $1.5 billion on the North Slope but probably will not realize any revenue from this venture for another 4 years or more.

* *Joint Association Survey of the Oil and Gas Producing Industry*, Sponsored by the American Petroleum Institute, Independent Petroleum Association of America and Mid-Continent Oil and Gas Association (published yearly).

Projected Oil and Gas Resources Discovered

By the end of 1970, a total of 26.9 billion barrels of oil-in-place and 31.5 TCF of gas had been discovered in all of Alaska.

Estimates of discoveries of oil-in-place during the 1971-1985 period range from 19.8 billion barrels (Case IV) to 40.6 billion barrels (Case I). Estimates of discoveries of total gas (both associated-dissolved and non-associated) range from 19.5 TCF (Case IV) to 63.2 TCF (Case I).

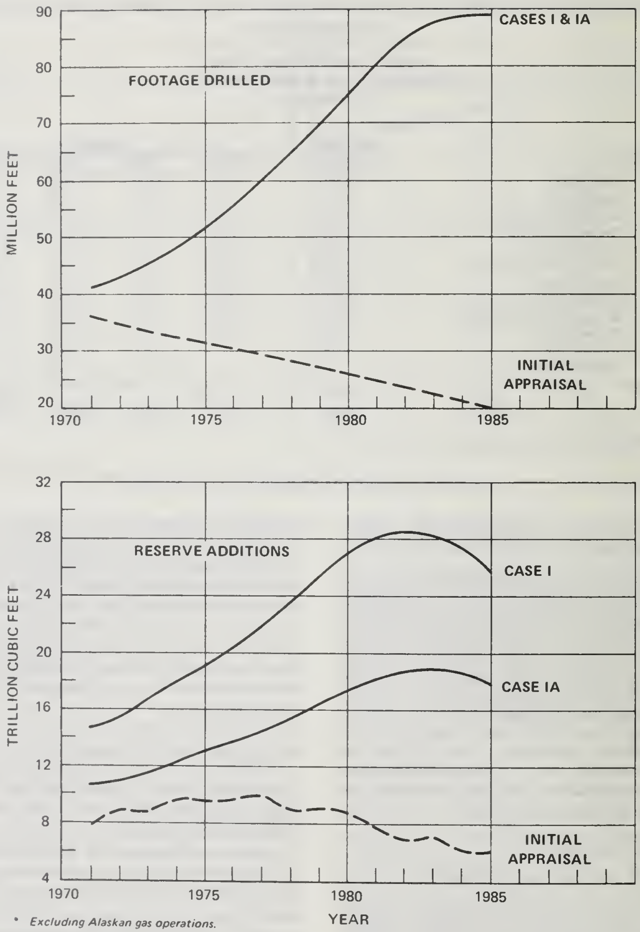
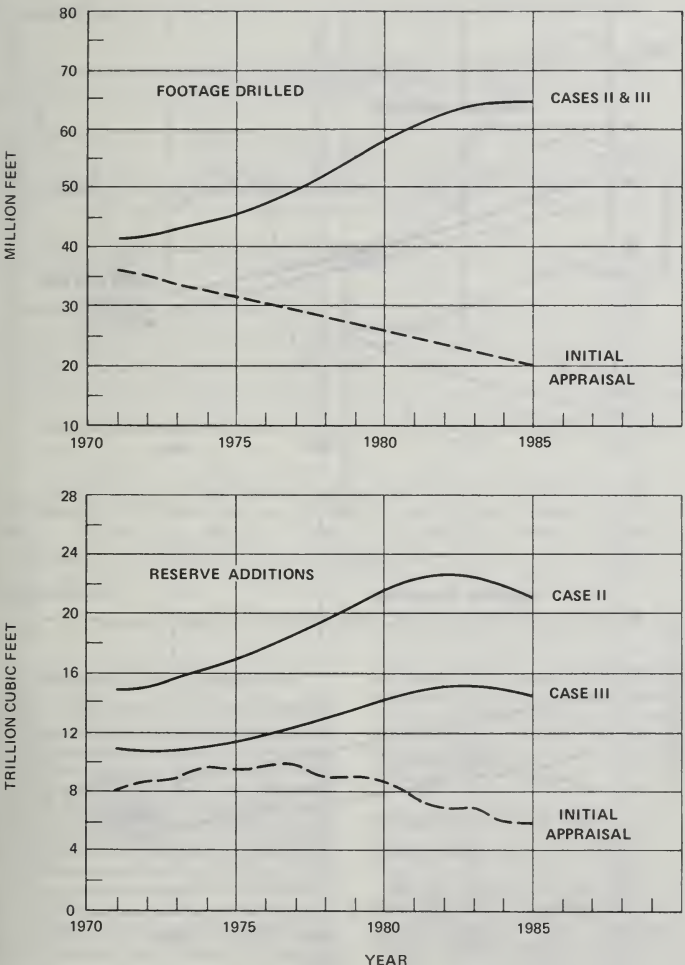


Figure 25. Gas Footage Drilled and Total Gas Reserve Additions (Cases I and IA).*



* *Excluding Alaskan gas operations.*

Figure 26. Gas Footage Drilled and Total Gas Reserve Additions (Cases II and III).*

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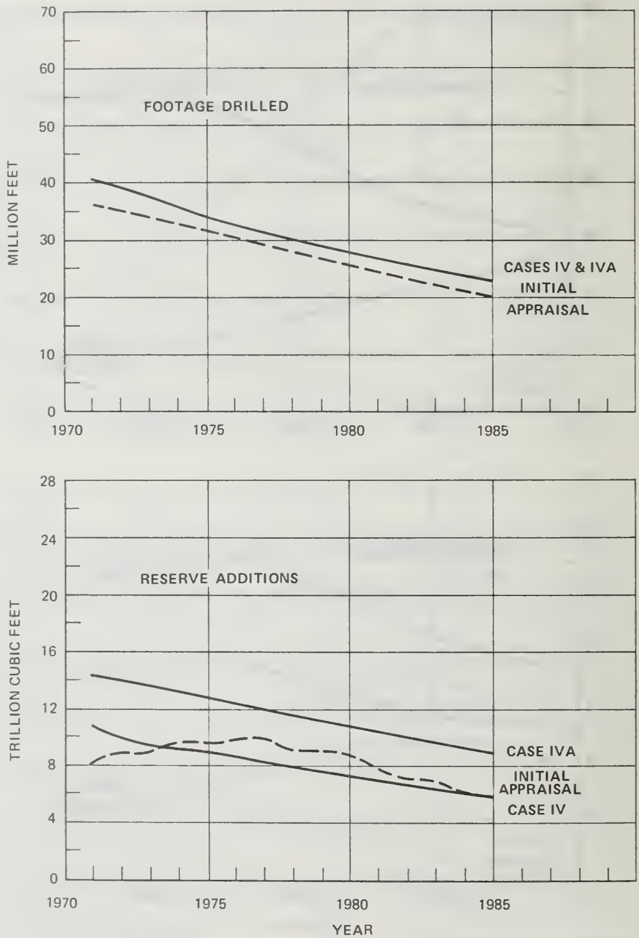
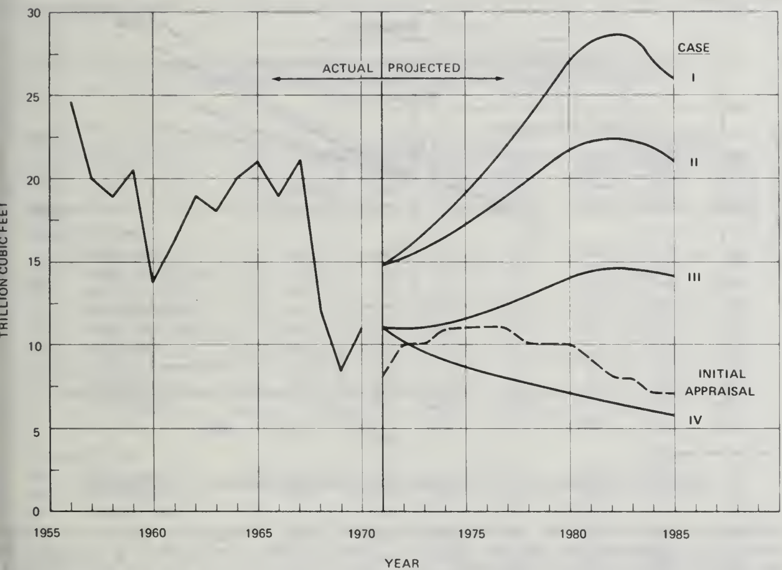


* *Excluding Alaskan gas operations*

Figure 27. Gas Footage and Total Gas Reserve Additions (Cases IV and IVA).*



* *Excluding Alaskan operations.*

Figure 28. Gas Reserve Additions—Non-Associated and Associated-Dissolved (TCF of Dry Gas).*

Estimated Production and Expenditures

The large potential impact of Alaska required that estimates of production schedules and of finding and developing expenditures be developed, even though experience in several of these areas of activity is quite limited. For Cases II through IV, it was assumed that sufficient reserves would be found to support production at pipeline capacity of 2 MMB/D. Case I considered the possibility of a more optimistic outlook for the North Slope, resulting in a production peak of 2.6 MMB/D by 1985.

Tables 56 and 57 summarize the estimated production schedules and exploration and development expenditures.

Operating costs for production and transportation for the North Slope cannot be projected with any accuracy until experience in additional drilling and actual production has been achieved. Since these costs and the timing of such activities enter into calculations of "price," the complete impact of Alaska during the next 15 years cannot be projected.

Economics — Oil and Gas

General Background

For any assumed level of return on net fixed assets and exploratory success level (finding rate), it is possible to determine both the total revenue and unit revenue required to support the selected drilling and concomitant producing activities. These are referred to as required "prices" for oil and gas and are presented as a guide to under-

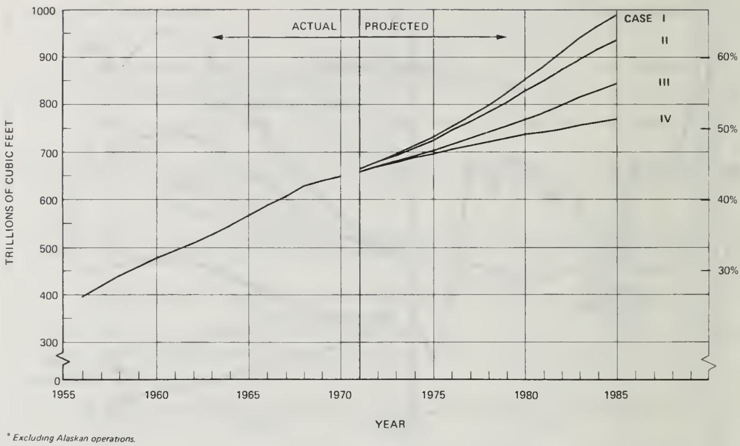


Figure 29. Cumulative Non-Associated and Associated-Dissolved Gas Discovered.*

standing the economics of the projected supply levels. It is emphasized that the unit revenues were derived *after* estimating the expenditures required for selected finding and drilling levels. The methodology employed in this study does not permit assumption of a unit price and derivation of a supply level and related exploratory activity. Accordingly, the data presented in the following discussion are not elements of a supply-price elasticity curve.

Petroleum exploration and production is an increasing-cost industry, and therefore average "prices" computed by the methodology employed tend to be lower than those needed to justify the new investments required to develop incremental supplies. Motivating factors other than price alone are therefore required to achieve the activity levels and supplies projected. Of particular importance is investor expectation of success and confidence in the direction, intent and stability of government policies. The impact of some of these non-price motivating factors were considered in the parametric studies.

All economic data—both historical and projected—were calculated on the basis of constant 1970 dollars. The historical figures were adjust from reported current dollars to constant 19 dollars by employing the Industrial Wholes Price Index. As a consequence, projected resu do *not* reflect inflation.

Oil and Gas Capital Requirements

The expenditures for finding and developi new oil and gas production in the lower 48 stat as projected for the four principal cases, are sho in Figure 34. These costs include exploration e penses, such as geological and geophysical cos lease rentals and dry holes, as well as capitaliz investments required to acquire leases, to drill a equip wells and leases, and to initiate additio recovery projects.

Historically, these costs have remained fai constant at approximately $5 billion per year. Ca IV maintains this level in the future with a slig increase toward the end of the 1970's. The ot three cases, based on a significant increase in dri ing, require dramatic increases in such expen tures. For Case I these annual expenditures rea

TABLE 50

REGIONAL NON-ASSOCIATED NATURAL GAS RESERVES ADDED DURING 15-YEAR PERIODS IN ENTIRE UNITED STATES
(Cumulative—TCF)

			Projected 1971–1985					
			High Finding Rate			Low Finding Rate		
Region		Actual 1956–1970	High Drilling Rate Case I	Medium Drilling Rate Case II	Low Drilling Rate Case IVA	High Drilling Rate Case IA	Medium Drilling Rate Case III	Low Drilling Rate Case IV
Onshore 48 States								
2	Pacific Coast	2.6	2.6	2.1	1.2	3.5	2.8	1.5
3	Western Rocky Mtns.	4.3	5.6	4.6	2.7	9.4	7.8	4.2
4	Eastern Rocky Mtns.	4.2	8.6	6.8	3.7	10.1	7.6	3.8
5	West Texas Area	19.4	43.5	36.8	22.5	33.6	27.9	16.5
6	Western Gulf Coast Basin	105.1	81.2	68.9	44.1	38.9	34.5	24.2
7	Midcontinent	33.1	30.7	25.2	15.0	17.7	15.2	9.9
8–9	Michigan, Eastern Interior	0.4	0.6	0.5	0.2	0.5	0.4	0.2
10	Appalachians	6.5	9.3	7.6	4.4	8.6	7.0	4.1
11	Atlantic Coast	–	0.4	0.2	0.1	0.3	0.2	0.1
	Total	175.6	182.5	152.7	93.9	122.6	103.4	64.5
Offshore 48 States								
2A	Pacific Ocean	0.5	0.4	0.3	0.1	0.4	0.3	0.1
6A	Gulf of Mexico	42.1	111.2	95.6	58.9	74.6	63.3	39.8
11A	Atlantic Ocean	–	15.1	11.4	4.9	10.1	7.6	3.3
	Total	42.6	126.7	107.3	63.9	85.1	71.2	43.2
Alaska		5.1	49.6	38.4	18.4	32.9	25.6	12.4
Total United States		223.3	358.8	298.4	176.2	240.6	200.2	120.1

$17.6 billion in 1985—three and one-half times the current level.

The same data with all of Alaska included is presented in Table 58, which shows total exploration and development expenditures required for the oil and gas business during the 1971-1985 period. These totals range from $88.0 billion in Case IV to $171.8 billion in Case I. For purposes of comparison, the total for similar expenditures in the 1956-1970 period was $79.8 billion expressed in constant 1970 dollars ($70.7 in current dollars).

As an example, expenditures for the various items comprising exploration, development and production for Case II are shown in Table 59 for the lower 48 states.

A combination of several factors is responsible for these increasing expenditures. The primary factor, of course, is the substantial increase in exploration and development activity. Also, future activity necessarily must shift from more mature areas into the unexplored frontier areas where the greater remaining potential lies. These frontiers for both oil and gas are also areas where severe operating conditions and logistical difficulties require high investments and operating expenses, e.g., Alaska and offshore. In addition, drilling depths must increase to reach the deeper potential resources, and consequently drilling costs increase. This is particularly true of gas for which much of the future potential is below 15,000 feet. The cost of drilling and equipping wells increases sharply as their depth increases and operating conditions become more severe as is indicated by Table 60.

The growing application of more secondary and

TABLE 51

PERCENT OF ULTIMATE NON-ASSOCIATED NATURAL GAS RESERVES DISCOVERED IN ENTIRE UNITED STATES AS OF DECEMBER 31, 1970, AND DECEMBER 31, 1985

Region		Actual 12/31/70 (Percent)	Projected as of December 31, 1985: High Finding Rate (Percent): High Drilling Rate Case I	Medium Drilling Rate Case II	Low Drilling Rate Case IVA	Low Finding Rate (Percent): High Drilling Rate Case IA	Medium Drilling Rate Case III	Low Drilling Rate Case IV
Onshore 48 States								
2	Pacific Coast	31.5	41.6	39.7	36.2	45.1	42.4	37.3
3	Western Rocky Mtns.	35.7	46.9	44.9	41.1	54.5	51.3	44.1
4	Eastern Rocky Mtns.	19.4	36.0	32.6	26.6	39.0	34.1	26.7
5	West Texas Area	26.8	69.7	63.1	49.0	59.9	54.3	43.1
6	Western Gulf Coast Basin	53.2	73.6	70.5	64.3	63.0	61.9	59.3
7	Midcontinent	46.9	60.7	58.2	53.6	54.9	53.7	51.4
8–9	Michigan, Eastern Interior	3.2	8.0	7.2	4.8	7 2	6.4	4.8
10	Appalachians	34.4	44.1	42.3	38.9	43.4	41.7	38.7
11	Atlantic Coast	0.2	8.9	4.6	2.4	6.7	4.6	2.4
	Total	42.9	61.8	58.7	52.7	55.6	53.6	49.6
Offshore 48 States								
2A	Pacific Ocean	13.2	23.7	21.1	15.8	23.7	21.1	15.8
6A	Gulf of Mexico	22.5	77.6	69.9	51.7	59.5	53.9	42.2
11A	Atlantic Ocean	–	27.7	20.9	9.0	18.5	13.9	6.1
	Total	17.6	66.4	58.9	42.2	50.4	45.0	34.3
Alaska		1.8	19.7	15.7	8.5	13.7	11.1	6.3
Total United States		30.9	54.8	50.8	42.7	47.0	44.3	38.9

tertiary oil recovery techniques also contributes substantially to the increase in costs. Continuation of the recent rising trend in offshore lease bonus payments, combined with the need for additional leases, is another factor behind increasing costs. Also, adequate protection must be provided for the environment as well as for health and safety, each of which further adds to costs.

Oil Revenues and Net Fixed Assets

The net fixed assets (book investment minus depreciation and excluding working capital) attributed to finding, developing and producing oil in the lower 48 states are shown in Figure 35. Since 1964, net fixed assets in the domestic oil exploration and production sector have declined as a result of insufficient investments being made to offset retirement of older assets. In all of the cases studied, this declining investment trend must b reversed. Even in the lowest supply case, th asset base must be increased to $25.5 billion b 1985.

Applying a set of five return assumptions (10 12.5, 15, 17.5 and 20 percent) to these net fixe assets permits calculating a range of average re quired "prices" of oil for each case. As an exam ple, these "prices" for Case II are displayed i Figure 36. For simplicity only the resulting "prices" for 10-, 15- and 20-percent returns are shown.

The rate of return on net fixed assets that wil be experienced in the future is unknown; however the range tested is broad enough to allow adequat evaluation of the variables studied. Again, thes "prices" are all expressed in constant 1970 dollar —any future inflationary effects would be additiv to the values shown.

Over the last 15 years, oil prices (expressed in constant 1970 dollars) have declined. The projections indicate the need for significant "price" increases, a strong reversal of "prices" being required if the industry is to attract the venture capital required.

For comparison, the Initial Appraisal assumption of constant oil price in the future is shown in Figure 36. In 1985, the rate of return on net fixed assets would decline to a completely unacceptable level of about 2 percent—this indicates the Initial Appraisal is not economically viable. While the supply projections could probably be achieved, the price required would have to be substantially higher than assumed for the Initial Appraisal.

Figures 37 and 38 repeat information previously shown for Case II to help illustrate the need for the projected reversal of the past price trend.

As discussed earlier, both the oil and gas segments of the industry are experiencing increasing real costs. With unit revenues declining and costs increasing, the return on investments realized has been insufficient either to attract or internally generate risk capital needed to expand exploration efforts. This is particularly true when no increased

TABLE 52

WELLHEAD PRODUCTION AND YEAR-END PROVED RESERVES OF NON-ASSOCIATED GAS—LOWER 48 STATES

	Wellhead Production (TCF)	Year-End Remaining Proved Reserves (TCF)	R/P
1970	16 9*	199 4*	11.8
1975†	19.4	180.0	9.3
1980†	19.2	172.6	9 0
1985†	19.7	174 6	8.9

* AGA

† Projections from Case II (medium drilling rate—high finding rate)

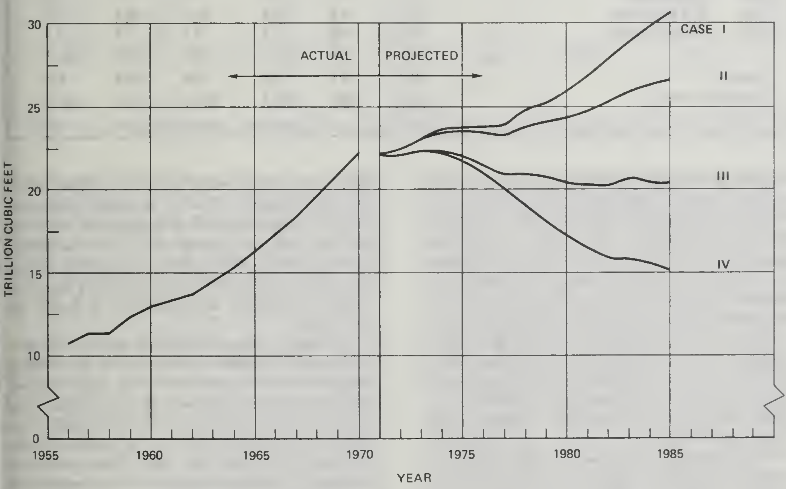


Figure 30. Wellhead Gas Production—Non-Associated and Associated-Dissolved United States (Including Alaska).

TABLE 53

TOTAL MARKETED VOLUMES OF NON-ASSOCIATED AND ASSOCIATED-DISSOLVED NATURAL GAS DURING 15-YEAR PERIOD IN ENTIRE UNITED STATES (TCF)

		Projected 1971–1985					
		High Finding Rate			Low Finding Rate		
		High Drilling Rate	Medium Drilling Rate	Low Drilling Rate	High Drilling Rate	Medium Drilling Rate	Low Drilling Rate
Region		Case I	Case II	Case IVA	Case IA	Case III	Case IV
Onshore 48 States							
2	Pacific Coast	5.7	5.5	5.3	6.0	5.7	5.4
3	Western Rocky Mtns.	9.4	9.1	8.6	10.3	9.9	9.0
4	Eastern Rocky Mtns.	8.0	7.5	6.6	7.8	7.3	6.4
5	West Texas Area	42.6	40.4	35.7	38.0	36.3	32.7
6	Western Gulf Coast Basin	126.5	122.1	113.0	108.3	106.5	102.2
7	Midcontinent	47.4	45.7	42.6	42.8	42.0	40.2
8–9	Michigan, Eastern Interior	0.4	0.3	0.3	0.3	0.3	0.3
10	Appalachians	7.4	6.9	6.0	7.0	6.6	5.8
11	Atlantic Coast	0.2	0.1	0.1	0.1	0.1	0.1
	Total	247.6	237.6	218.2	220.6	214.7	202.1
Offshore 48 States							
2A	Pacific Ocean	1.8	1.6	1.1	1.4	1.3	0.9
6A	Gulf of Mexico	81.5	75.5	62.5	64.7	60.8	52.6
11A	Atlantic Ocean	1.1	0.9	0.4	0.7	0.6	0.3
	Total	84.4	78.0	64.0	66.8	62.7	53.8
Alaska		20.8	17.8	7.9	17.6	15.1	6.8
Total United States		352.8	333.4	290.1	305.0	292.5	262.7

incentives in forms other than price have been available. In fact, one of these non-price incentives —favorable taxation treatment—was reduced by the 1969 Tax Reform Act. Changes in tax treatment directly affect return on investment by altering the after-tax income realized from the revenue received. The result of the declining economic attractiveness of this high-risk industry has been a reduction of the drilling effort over the last 15 years as shown in Figure 37. Furthermore, the restriction in access to the prospective areas with the highest hydrocarbon potential—the offshore regions—in the last few years has contributed to this decline in activity.

The increased oil and gas drilling activity projected for the future definitely indicates that more risk capital will be required. Thus, the long-standing trend toward decreasing attractiveness of the industry must be reversed quite substantially, and the return on investment must be sufficient to attract the increasing level of required investment If tax treatment remains unchanged, the only way that this can be accomplished is by increasing revenue and prices to offset projected increasing costs resulting from deeper drilling, more expensive recovery techniques, and operations in hostile environments.

Increased prices alone cannot achieve the projected supply. Exploration for oil and gas involve lead times on the order of several years between the time that the investment decision is made and the first revenue is received. For this reason, it i essential that the investor have a reasonably certain *expectation* that the political and economi situation (including contractual price increases) wi be sufficiently favorable in the future to warran committing large amounts of capital to high ris exploration ventures. Another factor essential t

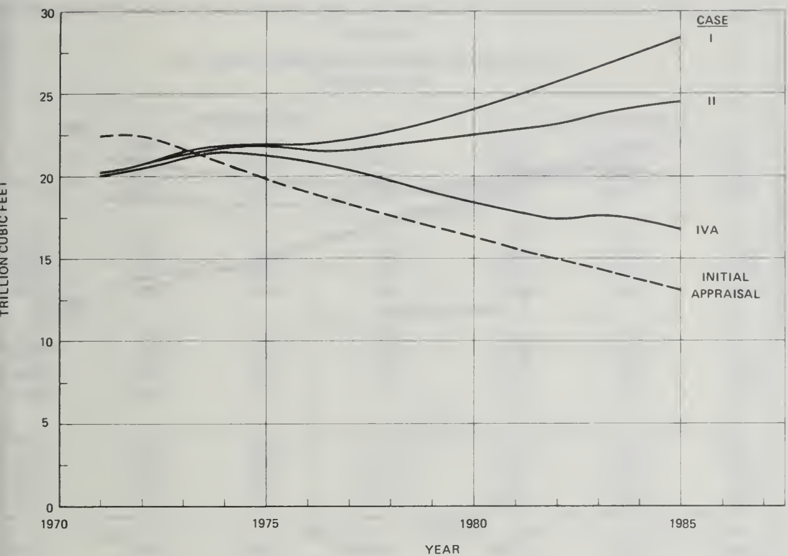


Figure 31. Total Marketed Gas Projections—Total United States (Including Alaska)—High Finding Rate.

expanded exploration efforts is producer confidence in being able to market any production discovered—assuming adequate protection of the environment. The delay of the proposed Alaskan pipeline is an example of this problem. The current hiatus on northern Alaskan exploration activity is a direct result of the uncertainty of market availability.

Only through a satisfactory combination of favorable political, regulatory and economic conditions and expectations will the declining trend in discovery of new primary reserves be improved as projected in Figure 38. Over the past 15 years, the oil industry has been able to maintain annual reserve additions at an almost constant level by increasing application of additional recovery technology to previously discovered reserves. Further substantial improvements of recovery efficiency are projected in the future, but it is recognized that this technology will be costly and will require long lead times. The application of improved techniques is responsible for a considerable amount of future reserves. However, unless the trend in new primary reserve discoveries is soon reversed, the opportunities for applying improved additional recovery methods will rapidly be depleted. This would result in a precipitous decline in total reserve additions, followed in a few years by a corresponding drop in oil production.

For comparative purposes, the calculated unit oil revenues for the low finding rate cases studied are shown in Figure 39. These values are shown only for the mid-range rate of return (15 percent). Similarly, the calculated unit oil revenues for the high finding rate cases are shown in Figure 40. The increases projected in the unit revenues range from a compound growth rate of 3.6 percent in Case IV to 5.4 percent in Case I. These "prices" are the *average* unit revenue computed from all oil

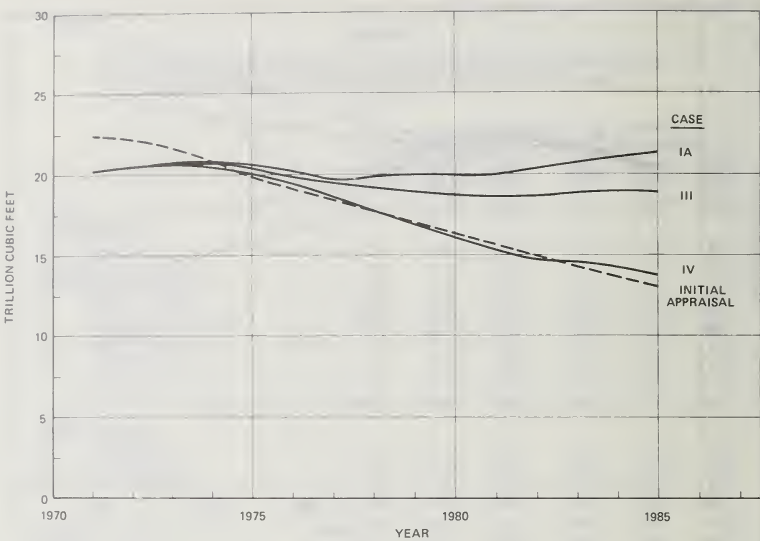


Figure 32. Total Marketed Gas Projections—Total United States—Low Finding Rate.

production, including production from both current proved and future reserves.

Economics of Newly Discovered Oil — 1971-1985

The method of computing the required oil "price" results in an *average* value for both the "old" oil discovered before 1971 and the "new" oil found during the 1971-1985 period. However, it is possible to use these average "prices" to investigate the economic attractiveness of just the new oil exploration and development activity assumed. This can be done by considering, as if it were a single project, all of the effort during the 1971-1985 period to find, develop and produce the new oil reserves. For this purpose, it is appropriate to employ the discounted cash flow (DCF) analysis technique commonly used to evaluate new projects. The DCF return which is calculated in this way can then be checked for reasonableness to see if the result is viable. (It should be kept in mind that this type of return is completely different from return on net fixed assets.)

A DCF calculation was made for Case II as an example, using the detailed assumptions outlined below. These assumptions, particularly on post-1985 performance, can influence the result of such a calculation quite significantly.

- "Price"—To calculate revenues for the first 15 years, the required oil "prices" calculated in Case II at a 15-percent return on net fixed assets were used for illustrative purposes. These "prices" increased from \$3.22 per barrel in 1971 to \$6.18 per barrel in 1985. In the absence of any projections after 1985, "price" was assumed constant at \$6.18 per barrel from

TABLE 54

NGL ANNUAL RESERVE ADDITIONS—LOWER 48 STATES
(Million Barrels)

	High Finding Rate			Low Finding Rate		
	High Drilling Rate Case I	Medium Drilling Rate Case II	Low Drilling Rate Case IVA	High Drilling Rate Case IA	Medium Drilling Rate Case III	Low Drilling Rate Case IV
			Condensate			
1971	99.6	99.6	98.3	72.4	72.4	71.4
1975	126.3	112.7	84.8	83.0	74.4	56.8
1980	177.7	141.3	70.6	111.9	90.0	46.4
1985	166.4	136.0	56.6	110.8	88.2	36.8
			Pentane and Heavier			
1971	97.6	97.6	96.5	72.9	72.9	72.1
1975	128.8	115.8	86.9	83.5	75.6	57.6
1980	169.9	136.5	69.7	102.1	83.2	44.0
1985	153.7	127.0	54.3	96.4	77.9	33.7
			LPG			
1971	193.6	193.6	191.4	147.9	147.9	146.3
1975	253.9	228.3	171.4	170.3	154.0	117.2
1980	368.8	294.4	148.5	233.4	188.4	98.2
1985	371.6	297.6	120.8	242.3	190.6	78.6
			Total NGL			
1971	390.8	390.8	386.2	293.2	293.2	289.8
1975	509.0	456.8	343.1	336.8	304.0	231.6
1980	716.4	572.2	288.8	447.4	361.6	188.6
1985	691.7	560.6	231.7	449.5	356.7	149.1

1985 until the time when all reserves would be depleted.

- Production Rate—The total new oil production schedule calculated in Case II was used for the 1971-1985 period. This started at zero in 1971 and reached a peak of 4.7 MMB/D in 1985. Production from the reserves remaining in 1985, together with subsequent additions for secondary and tertiary recovery, was scheduled using the same technique as for the 1971-1985 period. Production calculations were continued to the year 2015 which was the practical economic limit.

The total reserves developed in this case for new l amounted to 37 billion barrels—a recovery efficiency of approximately 48 percent of the 77 billion barrels of oil-in-place discovered.

The cumulative cash flow after income taxes for new drilling reached a *negative* $28 billion by 1985. Production thereafter resulted in a cumulative *positive* cash flow at final depletion of almost $46 billion. The resulting DCF return on new oil was 6 percent.

A 6-percent DCF return is rather low for this type of high risk investment and, as a before-the-fact expectation, would not attract the required risk capital on a single project basis. However, this value is on an after-the-fact basis after all risks have been taken. In addition, it is an industry aggregate and includes both successes and failures —some firms and individuals will have net losses,

TABLE 55

NGL PRODUCTION—LOWER 48 STATES
(MB/D)

	High Finding Rate			Low Finding Rate		
	High Drilling Rate Case I	Medium Drilling Rate Case II	Low Drilling Rate Case IVA	High Drilling Rate Case IA	Medium Drilling Rate Case III	Low Drilling Rate Case IV
	Condensate					
1971	399.7	399.7	399.7	399.7	399.7	399.7
1975	373.2	369.6	361.6	347.1	344.9	399.5
1980	417.3	391.0	337.8	338.9	323.0	289.6
1985	454.5	395.3	274.8	328.8	292.1	217.8
	Pentane and Heavier					
1971	507.4	507.4	507.4	507.4	507.4	507.4
1975	434.5	431.2	422.5	407.4	405.2	399.5
1980	462.5	437.3	383.3	381.6	366.6	334.0
1985	481.9	427.4	312.3	354.5	322.5	254.0
	LPG					
1971	1,068.2	1,068.2	1,068.2	1,068.2	1,068.2	1,068.2
1975	908.8	901.9	885.2	858.0	854.2	843.0
1980	936.4	886.6	781.4	788.5	757.8	691.0
1985	984.9	870.1	633.2	744.7	672.9	524.9
	Total NGL*					
1971	1,975.3	1,975.3	1,975.3	1,975.3	1,975.3	1,975.3
1975	1,716.4	1,702.7	1,669.3	1,613.4	1,604.4	1,581.9
1980	1,816.2	1,714.8	1,502.5	1,509.0	1,477.4	1,314.5
1985	1,921.4	1,692.9	1,220.3	1,427.9	1,287.4	996.7

* Totals may not agree due to rounding.

while others will receive adequate returns. Hence, the return on this composite basis should be expected to be lower than the level that is considered a desirable objective for a single project.

Gas [illegible] and Net Fixed Assets

Figure 41 shows the historical level of a year-end net fixed assets in the gas business and the projection of these levels as calculated for various cases studied. Assets have shown a modest increase during the past 15 years. However, in both the medium (Case II and III) or high (Case I) drilling cases, the asset base will have to be rapidly expanded to achieve the projected levels of supply.

In constant 1970 dollars, assets have increased from $3.9 billion in 1956 to $8.7 billion in 1970. By the end of 1985, the high drilling case (Case I) would result in assets increasing to more than $23 billion. The medium drilling case (Case II) would result in asset growth to almost $18 billion by the end of 1985.

In Case IV, where gas drilling declines approximately 4 percent per year, the asset base is calculated at $8.1 billion by the end of 1985. This compares with an asset base of $8.7 billion at year-end 1970.

The range of required average gas "prices" resulting from application of different returns on average net fixed assets are shown for the medium

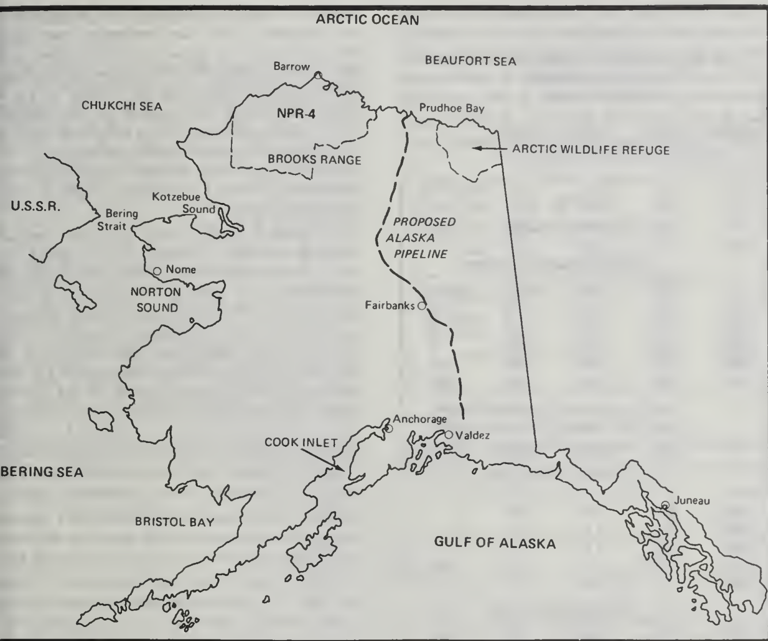


Figure 33. Area Map of Alaska.

illing rate combined with the high finding rate ase II) on Figure 42. Figure 43 shows the re- iired "prices" for the same drilling rate combined th the low finding rate (Case III). The returns ed are 10, 15 and 20 percent. As Figures 42 and indicate, current earnings from gas are sub- intially below the range of rates of return used these studies.

Figure 44 shows the average unit gas revenues juired for those cases which utilized the low ding rate (Cases IA, III and IV). Figure 45 ows the average unit gas revenues required for ose cases which utilized the high finding rate ases I, II and IVA). For illustrative purposes, the 15-percent rate of return shown on both figures was selected because it is at the middle of the range of returns used in these studies.

Figures 44 and 45 clearly show the magnitude of the effect that finding rate has on required unit revenue. For example, Case II (see Figure 45), which utilized the high finding rate and requires a unit revenue of 39.8 cents per MCF in 1985, can be compared with Case III (see Figure 44), which utilized the low finding rate and requires a unit revenue of 53 cents per MCF. Both of these cases involve the same level of drilling activity which can be controlled, as opposed to the finding rate which cannot.

Once discoveries have been made, oil and gas producing and marketing activities vary substantially in many respects. Generally the time lag experienced between the discovery of reserves and the start of production is longer in the case of gas than in the case of oil. When an oil well is completed, production can usually start almost immediately. Oil can be moved by truck or barge if no other facilities exist. Gas production must await the construction of gathering and pipeline facilities. The building of these facilities is dependent on developing a large enough volume of gas to justify the expenditure required for the construction. Certification proceedings before the FPC for interstate sales introduce additional time lags. This means that the capital invested in gas production must wait at least 1 or 2 years longer to begin generating revenue.

TABLE 56

ALASKAN PRODUCTION*

	Crude Oil—North Slope (MB/D)			
	Case I	Case II	Case III	Case IV
1975	0	0	0	0
1976	750	600	600	0
1980	2,190	2,000	2,000	0
1981	2,340	2,000	2,000	600
1985	2,600	2,000	2,000	2,000
	Non-Associated and Associated-Dissolved Gas—Total Alaska (TCF/Year—Dry Basis)			
	Case I	Case II	Case III	Case IV
	North of Brooks Range			
1975	–	–	–	–
1978	0.8	0.8	0.6	–
1980	1.4	1.3	1.1	–
1981	1.6	1.4	1.2	–
1983	2.5	2.2	2.2	0.7
1985	3.3	2.7	2.2	1.3
	South of Brooks Range			
1975	0.2	0.2	0.2	0.2
1978	0.2	0.2	0.2	0.2
1980	0.2	0.2	0.2	0.2
1981	0.5	0.5	0.4	0.3
1983	0.7	0.6	0.4	0.3
1985	1.1	0.9	0.6	0.4
	Total Alaska			
1975	0.2	0.2	0.2	0.2
1978	1.0	0.9	0.8	0.2
1980	1.7	1.5	1.3	0.2
1981	2.2	2.0	1.7	0.3
1983	3.2	2.8	2.4	1.0
1985	4.4	3.5	2.9	1.8

* None of the estimates include production for North Alaska offshore because severe operating conditions will probably prevent development during the 1971-1985 period. Totals may not agree because of rounding. Years included above in addition to 1975, 1980 and 1985 reflect projected commencement of logistical operations for oil and gas.

Gas generally moves under long-term contracts while oil does not. The field price of about two-thirds of total marketed gas production is regulated by the FPC, and these price ceilings have had a considerable effect on the price of the remaining gas which moves in intrastate commerce. Interstate gas sales prices have been reduced to the FPC area ceiling rates while contracted gas sales prices set below ceilings remain at the contract levels. This standard—i.e., ceiling price or contract price, whichever is lower—has resulted in a 1970 average unit gas revenue of 17.1 cents per MCF.*

Figure 42 shows that for Case II the 1970 average unit revenue (17.1 cents per MCF) is 2.5 cents per MCF lower than the calculated 1971 required average unit revenue of 19.6 cents per MCF at a 10-percent rate of return and 10.3 cents per MCF lower than the calculated unit revenue of 27.4 cents per MCF at a 20-percent rate of return. Extrapolation of these data leads to the conclusion that gas is earning approximately 7 percent on average net fixed assets under current conditions. This is an unattractive return considering the risks assumed by the investor-producer.†

* The 17.1 cents per MCF is the average wellhead value reported by the Bureau of Mines for 1970. For purposes of this discussion, the 17.1 cents per MCF is assumed to be on a comparable basis with the required unit "prices" calculated in this study. However, this value contains some amount for liquid content (estimated to be about 2 cents) and to that extent is overstated for comparative purposes with unit "prices" calculated in this study.

† The Bureau of Mines has recently published the 1971 wellhead value of natural gas as being 18.2 cents per MCF. This would indicate a 1971 rate of return on gas of about 8 percent. However, it should be kept in mind that this return is overstated to the extent that liquid values are a part of the 18.2 cents. If the liquid value were as much as 2 cents per MCF, then the indicated return on gas would be less than 6 percent.

Economics of Newly Discovered Gas — 1971-1985

The results of studies presented herein relate only to average unit gas revenues. No feasible method was found to incorporate into the computer program the vintaged ceiling price system imposed by federal regulation in combination with a second ceiling imposed by contract. The fact that some of the area ceilings are currently under attack in the courts and others are awaiting decision by the FPC adds to the complexity of the problem.

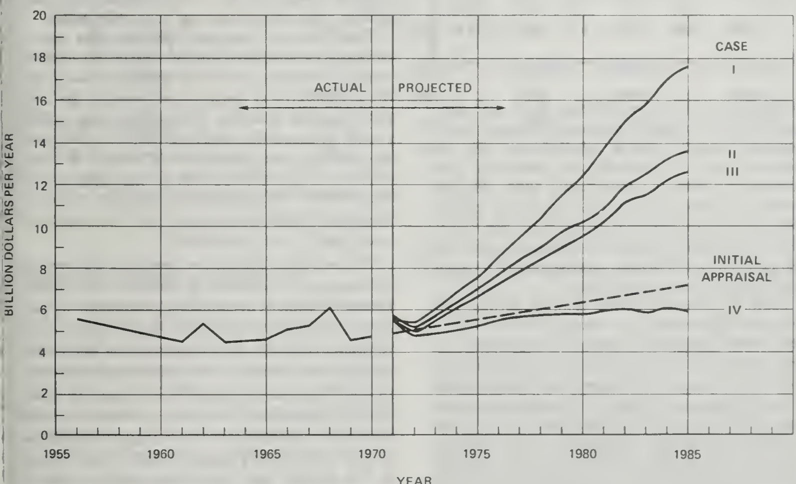
The level of unit revenue required from future gas sales at an assumed rate of return on total gas sales can be calculated by using data generated in the computer program. The program computes the total annual revenue required from gas sales. It also calculates the annual volume of marketed production from reserves found through the year 1970 separately from the volume of marketed production from reserves added in 1971 and subsequent years.

An essential determination which must be made is the annual unit revenue, or "price," to be received for future sales of gas found through the year 1970. The assumed unit "price" is then used

TABLE 57

ALASKAN EXPLORATION AND DEVELOPMENT EXPENDITURES
(Million Dollars)

	Case I	Case II	Case III	Case IV
	Non-Associated Gas—All Alaska			
1971-1975	207	192	192	164
1976-1980	1,226	991	978	543
1981-1985	2,28?	1,688	1,648	663
Total	3,715	2,871	2,818	1,370
	Oil—North Slope			
1971-1975	835	681	681	227
1976-1980	2,412	2,001	2,001	455
1981-1985	1,696	1,313	1,313	2,001
Total	4,943	3,995	3,995	2,683



* Excluding North Slope oil and Alaskan gas operations.

Figure 34. Exploration and Development Costs *—Oil and Gas (Constant 1970 Dollars).

TABLE 58

EXPLORATION AND DEVELOPMENT EXPENDITURES TOTAL UNITED STATES

(Billion Dollars)

	1971	1975	1980	1985	15-Year Total
			Case I		
Oil	3.6	5.4	8.6	12.5	113.1
Gas	2.1	2.7	4.6	5.8	58.7
Total	5.7	8.1	13.2	18.3	171.8
			Case II		
Oil	3.6	4.9	7.3	9.9	97.7
Gas	2.1	2.4	3.6	4.3	47.1
Total	5.7	7.3	10.9	14.2	144.8
			Case III		
Oil	3.5	4.5	6.6	8.8	88.8
Gas	2.1	2.4	3.6	4.3	46.3
Total	5.6	6.9	10.2	13.1	135.1
			Case IV		
Oil	3.5	3.5	4.1	5.0	61.5
Gas	2.0	1.8	1.7	1.5	26.5
Total	5.5	5.3	5.8	6.5	88.0

to calculate the revenue resulting from such production. This calculated revenue is deducted from the total annual revenue required, and the remainder must be generated from remaining production, i.e., from gas found after 1970. The remaining required revenue figure is divided by the annual produced volumes of gas discovered after 1970 to determine the unit revenue required for this gas. These calculations are performed for each year to derive annual unit "prices."

Table 61 shows marketed volumes of pre- and post-1970 discovered gas under Case III conditions. Table 62 shows the Case III average unit "prices" and calculated "prices" for gas production from reserves discovered post-1970 under three different assumptions. These three assumptions, which relate only to the "price" for gas discovered in 1970 and prior years, are as follows: (1) no escalation, (2) an escalation of 0.5 cents per MCF per year, and (3) an escalation of 1.0 cents per MCF per year. The price escalations are assumed to begin on January 1, 1973.

Table 62 shows that unit revenues required for production from reserves found after 1970 will be in the range of slightly less than $0.60 to a little more than $0.80 per MCF at a 15-percent rate of return in constant 1970 dollars. The level of these required unit revenues is, of course, influenced directly by the "price" received for production from reserves found through the year 1970. In general, the required unit revenues shown are comparable to, or well below, estimates of costs of alternative forms of gas supply with the exception of some overland imports.

Another fact which must be considered in examining the required unit revenues shown in Table 62 is the effect on consumer prices of *not* having adequate domestic supplies of gas. Many of the costs of transporting and distributing gas are fixed, in the sense that a smaller volume does not reduce the total cost but increases the unit costs of the smaller volume. In addition, there are substantial undepreciated investments in pipeline and distribution facilities. If supplies become inadequate, current depreciation rates would need to be increased. These two facts alone would exert substantial upward pressure on consumer prices.

These studies document the fact that gas is currently earning very low returns on investment, which is certainly one of the principal reasons for the present critical condition of domestic gas supply. Until this situation is remedied, there is little reason to expect that achievement of the increased gas drilling rates postulated in certain of these studies can be realized. One obvious approach to the problem of determining adequate economic incentives would be to let gas seek its competitive price level in the marketplace.

The required "prices" for marketed volumes of natural gas are expressed in constant 1970 dollars. Future inflation is of considerable concern to producers selling gas interstate under conventional contracts, most of which specify terms for the life of production or for 20 years. Without implying a future inflationary trend, it is important to quantify the significance of even a relatively small inflationary influence. As an example, the application of a 3-percent average annual inflation factor to the average gas "price" required in Case III in 1985 (Table 62) increases the constant 1970 dollar price of 53.0 cents to 82.6 cents per MCF.

TABLE 59

CASE II EXPENDITURES FOR EXPLORATION, DEVELOPMENT AND PRODUCTION OF OIL AND GAS—1971-1985*
(Million Dollars)

	1971	1975	1980	1985	15-Year Total
Exploration					
Dry Holes	839	1,033	1,364	1,683	18,500
Lease Acquisitions	817	1,420	2,385	3,166	29,509
Lease Rentals	140	162	238	332	3,223
Geological & Geophysical	530	610	771	966	10,713
Total	**2,326**	**3,225**	**4,758**	**6,147**	**61,945**
Development					
Drilling & Equipping Producing Wells	1,916	2,312	3,105	4,076	42,062
Equipping Leases	1,103	1,325	2,246	3,350	31,631
Gas Plant Development	209	167	140	94	2,250
Total	**3,228**	**3,804**	**5,491**	**7,520**	**75,943**
Total Exploration and Development	**5,554**	**7,029**	**10,249**	**13,667**	**137,888**
Production					
Producing Costs	2,533	2,607	3,084	3,767	44,467
Production & Ad Valorem Taxes	958	1,061	1,388	1,893	19,623
Total	**3,491**	**3,668**	**4,472**	**5,660**	**64,090**
Gas Plant Expenses	469	458	435	429	6,688
Overhead Expenses	832	959	1,211	1,518	16,835

* Excludes North Slope oil and all Alaskan gas.

Parametric Studies — Oil and Gas

It is important for decision makers to know how responsive or sensitive supplies and prices would be to changes in basic assumptions about finding rates, drilling costs, changes in government policy, etc. The technique used to provide this information was to vary only one assumption or parameter at a time to determine its effect upon the results. These studies were normally done on Cases II and III in order to keep the number of evaluations to a manageable size. However, in a few instances Cases I and IV were also tested. Unless otherwise indicated, the North Slope oil and Alaskan gas operations were not included in these analyses.

The results of these parametric studies are expressed in terms of the incremental effects on Case II and Case III producing rates and "prices." For "price" effects, five rates of return in the 10- to 20-percent range were investigated; the 15-percent return level is the middle value in the spectrum evaluated and is reported here for illustrative purposes. Higher rates of return would naturally require higher "prices."

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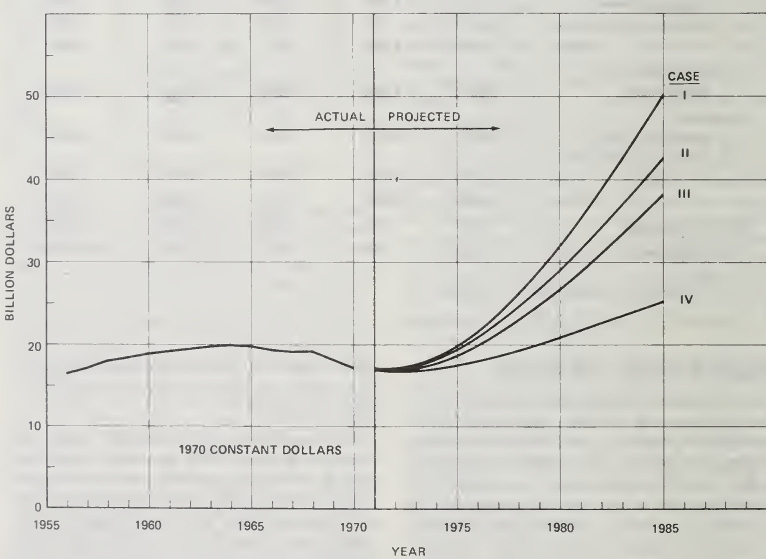
TABLE 60

AVERAGE COST PER WELL DRILLED—1968-1970*

Depth Range (Feet)	Onshore 48 States	Offshore 48 States	Alaska
0 - 4,999	$ 25,000	$ 212,000	$ 382,000
5,000 - 9,999	83,000	367,000	1,508,000
10,000 - 14,999	251,000	598,000	1,869,000
15,000 - 19,999	732,000	1,115,000	2,894,000
20,000 and over	1,485,000	2,690,000	

* Developed from *Joint Association Survey of the Oil and Gas Producing Industry*, Sponsored by the American Petroleum Institute, Independent Petroleum Association of America and Mid-Continent Oil and Gas Association (published yearly).

No attempt was made to determine the effect that the different "prices" would have on drilling activity or, in economic terms, to determine the price-elasticity of supply. It should be emphasized that the required "price" is that average "price" required to yield a given rate of return on net fixed assets, which includes a heavy component of previously discovered oil and gas reserves. It is not the "price" required to give the industry adequate incentive to discover and develop new reserves. Nevertheless, these parametric studies do provide an indication of the relative effect on supplies and "prices" of reasonable variations in the basic parameters.



* *Excluding North Slope operations.*

Figure 35. Net Fixed Assets—Oil Operations (Billion Dollars).*

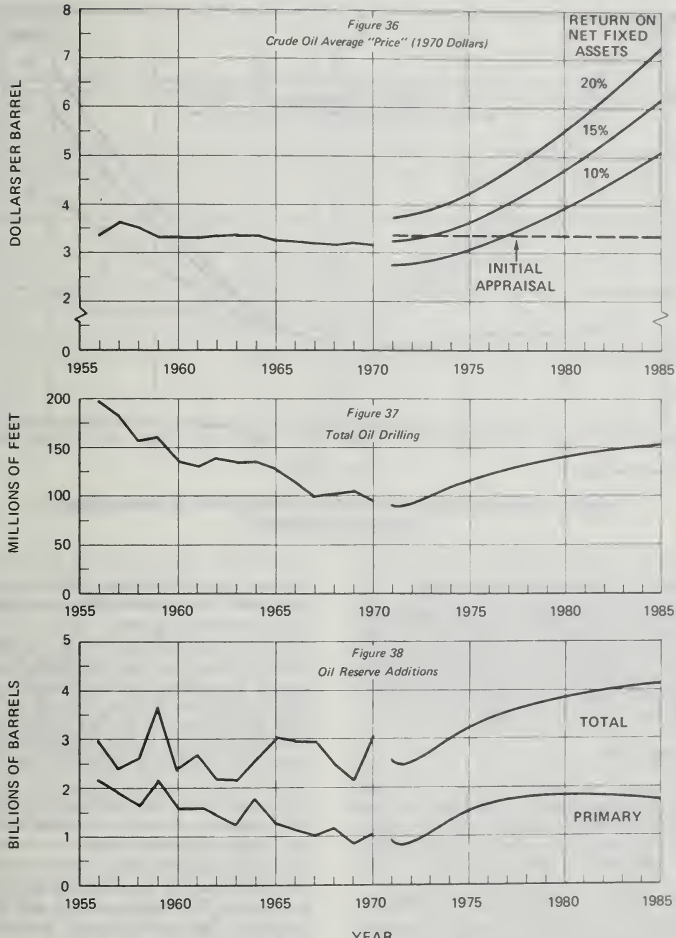


Figure 36
Crude Oil Average "Price" (1970 Dollars)

Figure 37
Total Oil Drilling

Figure 38
Oil Reserve Additions

* ***Excluding North Slope operations.***

Figures 36-38. Oil Average "Price," Drilling and Reserve Additions.*

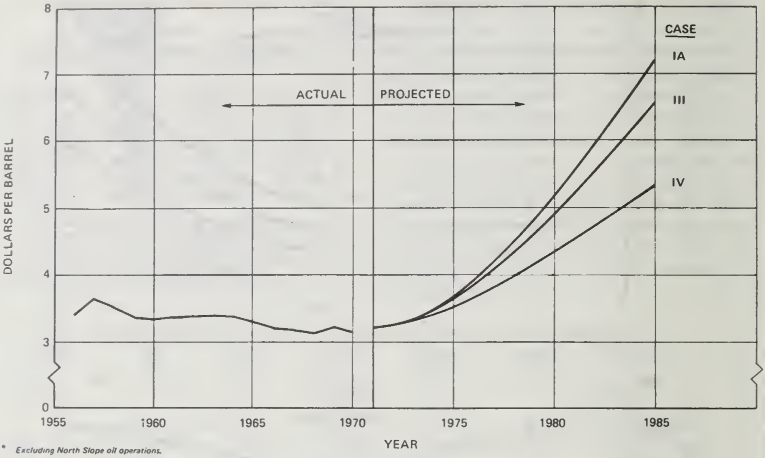


Figure 39. Required Crude Oil "Price"—Low Finding Rate—15-Percent Return (Constant 1,970 Dollars).*

Sensitivity of Physical Assumptions

While a large number of physical assumptions were made in developing the base cases, the most significant of these were finding rates and application of additional recovery processes. Several studies were made to examine the sensitivity of production and "prices" to these parameters.

Finding Rates

The amount of hydrocarbons found per foot drilled strongly influences both production and "prices." This factor—which embraces an element of risk as well as exploratory skill—not only helps determine the projected supply but also heavily influences future required "prices."

Two finding rates were applied to each of the three drilling rates. It is highly unlikely that either the high or low finding rate would occur in all regions every year over a 15-year period, and the actual average finding rate would more probably fall between the two. The resulting supply and required "prices" would then fall within the range established by the two finding rates applied to the assumed drilling rates.

The effect of finding rates on production and required "prices" is shown in Table 63. Case II utilized the medium growth drilling rate and the high finding rate, whereas Case III utilized the same drilling rate but the low finding rate.

Table 63 indicates that the 1985 production rate would be significantly lower and the required "price" in 1985 would be higher if a low rather than a high finding rate were experienced. A similar comparison of cases at the other two drilling rates yields comparable results.

Another parametric study was run to evaluate the possibility that the historical oil found was understated. This might occur if past API data on reserve "revisions" included some oil added as a result of increases in oil-in-place. To the extent that any such additions to oil-in-place had occurred, the historical finding rates would be too low. An analysis of the API data indicated this

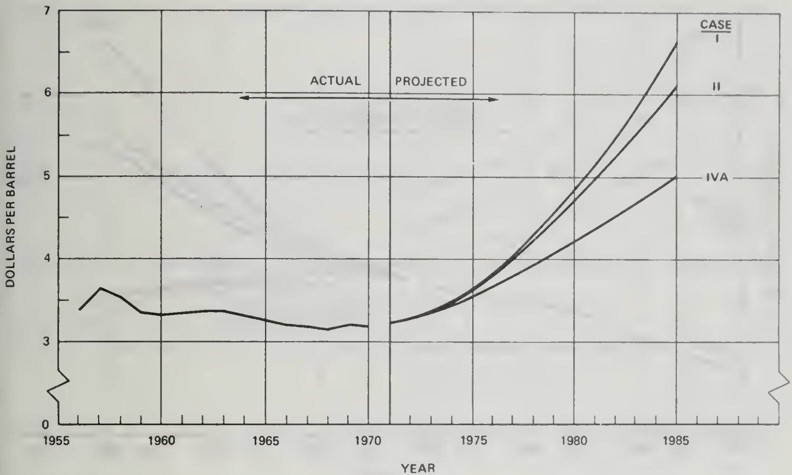


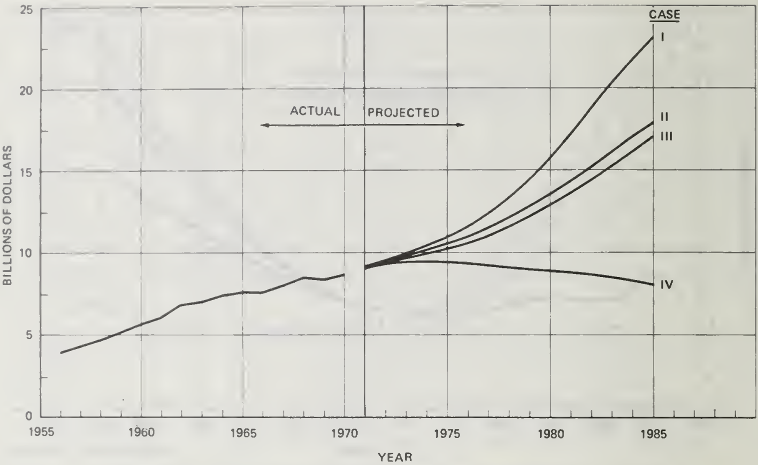
Figure 40. Required Crude Oil "Price"—High Finding Rate—15-Percent Return (Constant 1970 Dollars).*

error should not exceed 5 percent. The results of two cases in which the oil finding rates were increased by twice the potential error (10 percent) are shown in Table 64. As indicated in this table, the maximum effect occurs in Case II, in which the 1985 production rate increases about 0.5 MMB/D (less than 5 percent) and the required "price" is reduced by about 4 percent. These results substantiate the judgment that the method of handling API reserve statistics provides reliable results.

Although the high finding rate projection includes an allowance for discovery of major fields, the possibility exists of discovering another field near the size of the largest producing field in the lower 48 states. The impact of such a find was evaluated by hypothesizing the discovery of a 5-billion-barrel (recoverable oil) offshore field in 1978. The results of this hypothesis on Cases II and III are shown in Table 65. A discovery of this magnitude may have a low probability, particularly when assuming the high finding rate. Nevertheless, it could significantly affect the supply picture for the United States if this oil field were found in an accessible area so that it could be easily marketed. In 1983, the year of peak production, such a field could increase the Nation's oil supply by 16 to 19 percent (exclusive of the North Slope). Furthermore, such a major discovery would also stimulate industry activity resulting in a production increase which would exceed that shown in Table 65. The effect upon "price" is uncertain in that exploration and development investment would be stimulated as would the bidding on leases. The increased revenue would probably be spent on this expanded effort.

Additional Oil Recovery

The rate of application of additional recovery processes assumed was consistent with historical increases in oil recovery efficiency. If, because of increased incentive or a technological break-



* *Excluding Alaskan gas operations.*

Figure 41. Year-End Net Fixed Assets—Gas Operations.*

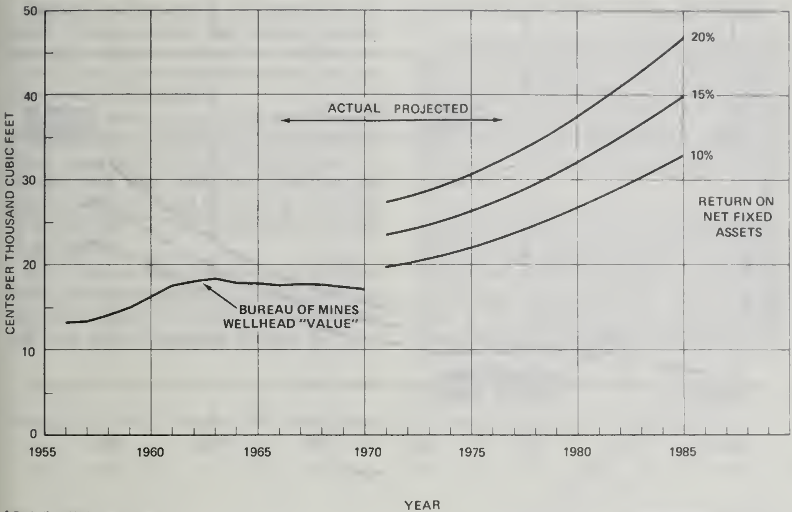
through, additional recovery projects were implemented earlier and applied to more fields, the of secondary and tertiary recovery projects was increased by about 50 percent and accelerated by 2 years. This had the effect of raising the 1985 cumulative recovery efficiency from 37 percent to 39 percent of the oil-in-place discovered. The results are shown in Table 66. Production would production would be significantly increased. Studies were made against the highest and lowest supply cases (I and IV) in which implementation greatly increase in both cases. In Case IV, significant "price" increases would be required because there is relatively little production to provide required revenues; hence, per barrel revenues must be higher. Since Case I already has a high production base, the per barrel "price" increases required are much less significant. A factor not accounted for is any cost reduction that might be associated with technological improvement.

Oil Reserves/Production Ratio

A parametric study was conducted on Case II to determine the impact of assuming that the oil R/P could be reduced from 8.9 in 1970 to about 8.0 in 1975 and maintained at that level thereafter (see Table 67). It can be seen that U.S. oil production could be increased by as much as 7 percent in 1975. This acceleration of production could result in about a $0.26 reduction in 1985 crude "price."

Basic Cost Parameters

To test the sensitivity of oil and gas "prices" to drilling costs, operating expenses and investments in additional recovery projects, parametric studies were made by separately increasing each of these items by 10 percent. The results are shown in Tables 68, 69 and 70.



* *Excluding Alaskan gas operations.*

Figure 42. Required Average Gas "Prices"—Case II (Constant 1970 Dollars).*

Environmental, Health and Safety Costs

In the past several years, the oil and gas industry has devoted a significant part of its investments and operating costs to protecting the environment and promoting health and safety. These historical costs are reported by the API and are included in the total investment and expense projections.* However, in 1970 much more stringent regulations of this type governing offshore operations were implemented, causing a significant rise in costs. These costs were projected separately in the methodology used in this parametric study.

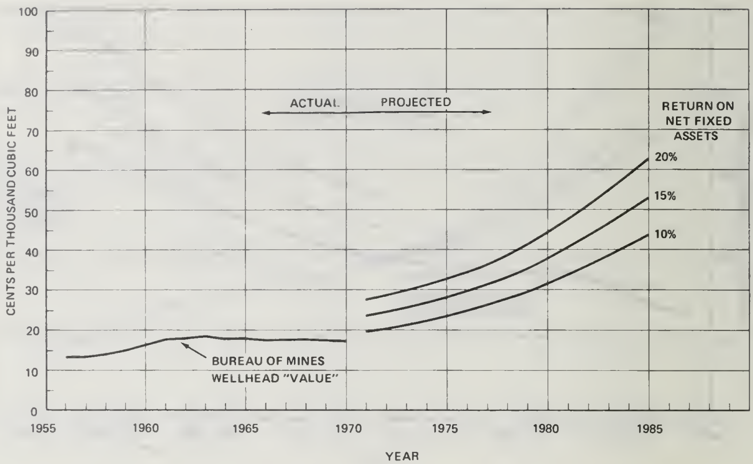
To determine the economic impact of further regulations of this nature, a parametric study was made in which these costs were arbitrarily doubled. The impact of this doubling on exploration and production economics is quite substantial, as shown in Table 71.

Thus, increasing restrictions by this amount could effectively increase required revenues by about $1 billion in 1985—an amount equivalent to one-fifth of the total drilling expenditures in that year. This emphasizes the importance of promulgating more stringent regulations only when the benefits to be obtained warrant the costs involved. This is particularly true when consideration is given to the fact that most of these increased costs will affect the economics of the offshore areas which are so important to developing increased future supplies.

Impact of Government Policy Changes

Parametric studies were designed to evaluate the impact of the critical policy options available to the Federal Government, primarily in two areas:

* API, *Report on Air and Water Conservation Expenditures of the Petroleum Industry in the United States, 1966-1970*, API Publication No. 4075 (February 1971).



* *Excluding Alaskan gas operations.*

Figure 43. Required Average Gas "Prices"—Case III (Constant 1970 Dollars).*

(1) leasing policy on federal lands in offshore and frontier areas and (2) taxation policy. Several alternatives were examined in each of these categories.

Federal Leasing Policy—Lease Availability

The base cases assumed that, with California added, the announced Department of the Interior lease sales schedule will be representative of future sales. Only a 5-year period was covered by the schedule, so it was necessary to extrapolate sales beyond 1975. Although Interior's schedule does not state the amount of acreage to be offered, it is assumed that sufficient acreage will be made available to provide the drilling opportunities projected. Analysis of potential acreage currently unleased and the acreage required for drilling indicates that this is a reasonable assumption if a national energy policy were designed to encourage increasing domestic supplies.

Recently, extreme concern for protection of the environment has created opposition to the granting of any additional offshore leases. Parametric studies were made to determine the effect on domestic U.S. production of eliminating or deferring all new federal lease sales.

The first analysis assumed that no new sales would be held offshore; however, existing acreage under lease could be developed. Table 72 shows the impact that this would have on U.S. production. If such an action were taken, it would decrease domestic production for Case II by over 2 MMB/D of crude oil and 5 TCF per year of gas in 1985—over one-fifth of the oil and gas production from the lower 48 states. Figure 46 shows the areas in which the oil production would be lost. Also shown on Figure 46 is the amount of North Slope production that would also be lost if it is not brought to market. Environmental overreaction could reduce total U.S. oil producing capacity in 1985 to two-thirds of its potential.

Similarly, the amount of gas production that would be lost from each area without additional leasing by the government is shown in Figure 47. In this case, up to 35 percent of the 1985 gas supply would be eliminated.

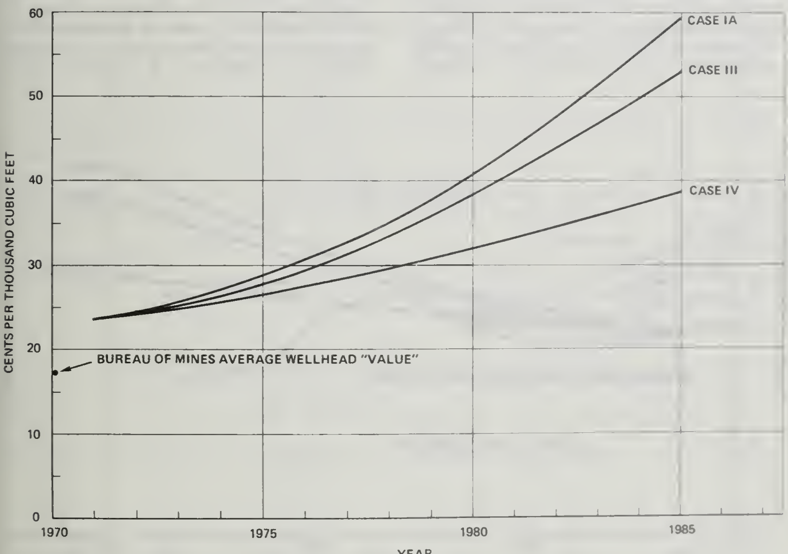
Table 73 shows the production cutback which would occur if new offshore leasing on the Gulf Coast were delayed until 1975 and eliminated in all the other areas. Under this condition, the country would be denied in excess of 1 MMB/D of oil and over 1 TCF of gas per year at the end of the period.

The effect on supply of delaying all offshore leasing for 5 years is shown in Table 74, while the effects of delaying only Pacific Coast offshore leasing for 5 years are depicted in Table 75.

Federal Leasing Policy—Leasing Method

Large bonus payments made to the Federal Government for leases have a very significant impact on the cost of oil and gas. A quantitative assessment was developed of the portion of future oil and gas "prices" that results from the assumptions used as to the cost of cash-bonus payments for offshore federal leases. The results are shown in Table 76.

It is obvious that an elimination of sealed, cash-bonus payments would have a sizable impact on both oil and gas "prices" in the longer term. By 1985, eliminating bonus payments would decrease "prices" by \$1.14 to \$1.33 per barrel of oil and 9.2¢ to 12.3¢ per MCF on all production under Case II or Case III conditions. The impact on off-



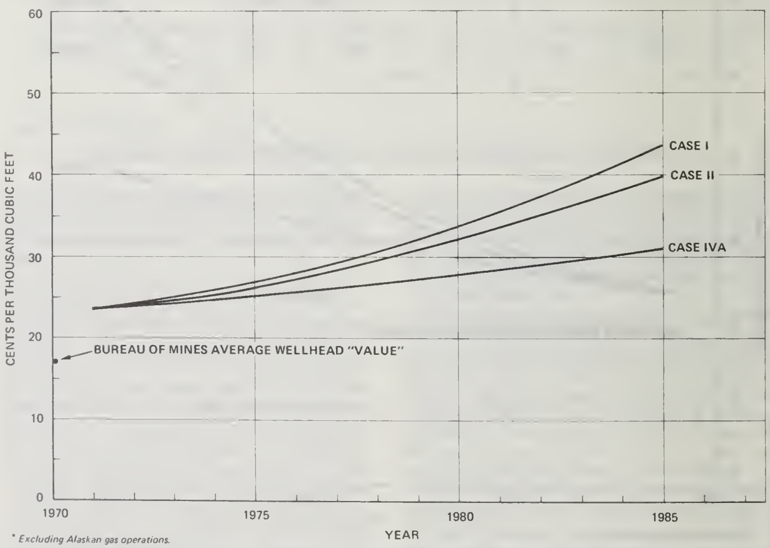
* *Excluding Alaskan gas operations.*

Figure 44. Required Average Gas "Price" Projections—15-Percent Return on Net Fixed Assets—Low Finding Rate.

shore economics would be even more than indicated—about four times as great—if all the bonus costs were related strictly to *offshore* production from reserves found after 1970.

One option open to the Federal Government for affecting activity and prices is the method used to grant the leases. Several types and variations of systems have been proposed as alternatives to the current system of sealed, cash-bonus payments assumed in all of the base cases. Two systems were considered for evaluation—royalty bidding and work programs. These are representative of the spectrum of alternatives that are available.

The effect of royalty bidding on supply and "price" is not subject to quantitative analysis in the abstract. Its impact depends on the detailed specification of how bids must be submitted, how the leases are administered once awarded, whether bids contain work commitments, as well as a host of other complex issues. The cost-benefit relationship from the public point of view depends on such unknowns as the specific royalty bid *vs.* the cash alternative bids that might be made on each tract. It also depends on whether the exploratory well is successful or dry, on the size of any reserve that might be found, on whether it is oil or gas that is found, and on the inclusion of any provisions for royalty reduction in the lease. All of these factors contributed to the conclusion that such a system could not be effectively analyzed in this study. They similarly constitute the major drawback of the system from a public interest point of view—the inability to evaluate which royalty bid on a tract is the "highest bid" and whether it is more advantageous than the cash-bonus alternative.



* *Excluding Alaskan gas operations.*

Figure 45. Required Average Gas "Price" Projections—15-Percent Return on Net Fixed Assets—High Finding Rate.*

TABLE 61

ANNUAL MARKETED VOLUMES OF ALL NATURAL GAS IN LOWER 48 STATES—
CASE III, LOW FINDING RATE, MEDIUM DRILLING RATE
(TCF)

	Volume Marketed from All Reserves Found Before 1971	Volume Marketed from All Reserves Found After 1970	Total Volume Marketed from All Reserves
1975	16.9	3.3	20.2
1980	10.6	7.0	17 6
1985	6.4	9.8	16.2

Work programs similar to the systems used by the United Kingdom in the North Sea were evaluated in a parametric study. In this system, leases are granted to operators who in turn agree to perform a stipulated amount of exploratory activity on these tracts. Only a minimal bonus or no bonus at all is charged. If a workable and equitable work program system could be developed within the confines of the political structure of the United States, it would be reasonable to expect an increase in drilling. A parametric study was made on Cases II and III assuming work programs would increase drilling to Case I levels in offshore regions. The reduction in bonus would be more than adequate

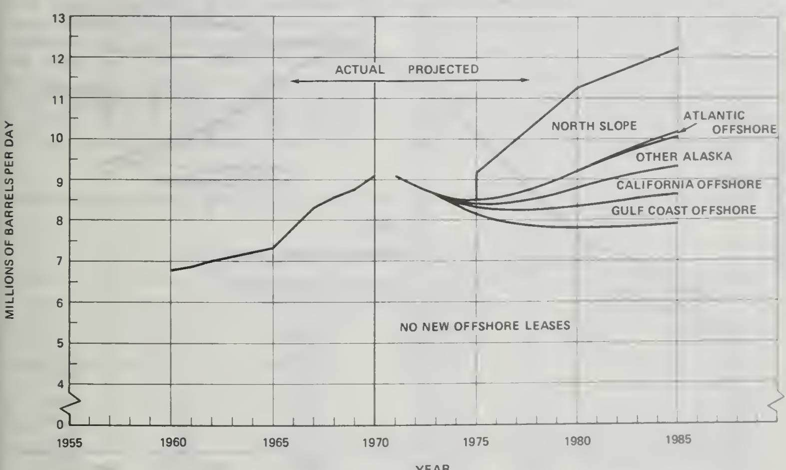


Figure 46. Effect of No New Offshore Leases or North Slope Production—Daily Oil Production (Case II)

TABLE 62

REQUIRED "PRICES" FOR MARKETED VOLUMES OF ALL NATURAL GAS IN LOWER 48 STATES TO ACHIEVE A 15-PERCENT RETURN ON NET FIXED ASSETS–CASE III, LOW FINDING RATE, MEDIUM DRILLING RATE
(Cents per MCF in Constant 1970 Dollars)

		Escalation of "Prices" Effective 1/1/73 for Marketed Volumes from Reserves Found Prior to 1970					
		No Escalation		0.5¢/MCF per Year		1.0¢/MCF per Year	
	Avg. "Price" for Total Volume Marketed from All Reserves	"Price" for Vol. Mktd. from All Reserves Found Before 1971	"Price" for Vol. Mktd. from All Reserves Found After 1970	"Price" for Vol. Mktd. from All Reserves Found Before 1971	"Price" for Vol. Mktd. from All Reserves Found After 1970	"Price" for Vol. Mktd. from All Reserves Found Before 1971	"Price" for Vol. Mktd. from All Reserves Found After 1970
1970	17.1	17.1	-	17.1	-	17.1	-
1975	27.9	17.1	82.5	18.6	74.9	20.1	67.3
1980	37.8	17.1	69.3	21.1	63.2	25.1	57.1
1985	53.0	17.1	76.4	23.6	72.2	30.1	67.9

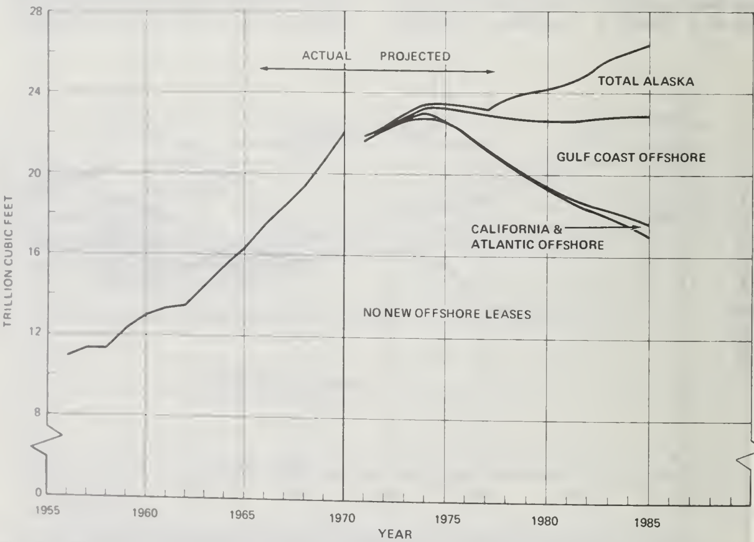


Figure 47 Effect of No New Offshore Leases or Alaskan Production—Wellhead Gas Production (Case I

TABLE 63

CHANGE OF FINDING RATE FROM HIGH TO LOW
(Medium Drilling Growth Rate)

	Production			
	MMB/D		TCF/Yr Marketed	
	Case II Oil	Change to Case III	Case II Gas	Change to Case III
1971	9.1	–	20.0	–
1975	8.5	- 0.4	21.6	- 1.4
1980	9.2	- 1.0	21.1	- 3.5
1985	10.2	- 1.6	21.3	- 5.1
	"Prices" at 15% Return			
	$/Bbl		¢/MCF	
	Case II Oil	Change to Case III	Case II Gas	Change to Case III
1971	3.22	–	23.5	–
1975	3.63	+ 0.04	26.2	+ 1.7
1980	4.73	+ 0.22	31.8	+ 6.0
1985	6.18	+ 0.42	39.8	+ 13.2

TABLE 64

INCREASE OF OIL FINDING RATES
BY 10 PERCENT

	Oil Production (MMB/D)			
	Case II		Case III	
	Base	Change	Base	Change
1971	9.1	-	9.1	-
1975	8.5	+0.1	8.1	+0.1
1980	9.2	+0.3	8.2	+0.2
1985	10.2	+0.5	8.5	+0.3
	"Prices" at 15% Return ($/Bbl)			
	Case II		Case III	
	Base	Change	Base	Change
1971	3.22	-	3.23	-
1975	3.63	-0.05	3.67	-0.04
1980	4.73	-0.15	4.95	-0.12
1985	6.18	-0.25	6.60	-0.20

to finance the additional drilling, and it was assumed that the difference would be reflected in lower "prices." The results are shown in Table 77.

It is apparent that implementation of a work program system could have a substantial effect on both supply and "price." However, the political reality of such a system must be seriously questioned. The impact on price could be a reduction of as much as $1.00 per barrel and $0.11 per MCF on total domestic production from the base case "prices" calculated. These calculated results make no allowance for the possible inefficient use of capital and equipment to satisfy work commitments on tracts which prove to be only marginally attractive following initial exploratory work. There might also be a tendency to defer activity under a work program bid as compared to a cash-bonus-payment system, which is also not evaluated.

TABLE 65

DISCOVERY OF A 5-BILLION-BARREL OIL FIELD IN 1978

	Oil Production (MMB/D)			Percentage Increase in U. S. Production	
	Case II	Case III	Increase Due to Discovery	Case II	Case III
1979	9.0	8.1	0.1	1	1
1980	9.2	8.2	0.7	7	9
1981	9.4	8.2	1.0	11	12
1982	9.6	8.3	1.3	13	16
1983	9.8	8.4	1.6	16	19
1984	10.0	8.4	1.4	14	17
1985	10.2	8.5	1.2	11	14

TABLE 66

INCREASE OF OIL RECOVERY EFFORTS

	Oil Production (MMB/D)			
	Case I	Change	Case IV	Change
1971	9.1		9.1	
1975	8.5	+0.8	8.0	+0.8
1980	9.6	+2.0	7.6	+1.8
1985	10.9	+1.8	7.4	+1.2
	Oil "Prices" at 15% Return (S/Bbl)			
	Case I	Change	Case IV	Change
1971	3 22		3.22	·
1975	3.65	+0.44	3.57	+0.48
1980	4 90	+0.71	4.39	+1.02
1985	6.69	+0.51	5.28	+1.11

TABLE 67

REDUCTION OF THE OIL RESERVES TO PRODUCTION RATIO

	Production		"Prices" at 15% Return	
	Oil (MMB/D)		Oil (S/Bbl)	
	Case II	Change	Case II	Change
1971	9.1	–	3.22	–
1975	8.5	+0.6	3.63	-0.22
1980	9 2	+0.4	4.73	-0.28
1985	10.2	+0.2	6.18	-0.26

TABLE 68

INCREASE OF 10 PERCENT IN DRILLING COSTS

	Oil "Prices" at 15% Return (S/Bbl)			
	Case II	Change	Case III	Change
1971	3 22	-	3.23	–
1975	3.63	+ 0.05	3.67	+ 0.05
1980	4 73	+ 0 10	4 95	+ 0.10
1985	6 18	+ 0.15	6.60	+ 0.14
	Gas "Prices" at 15% Return (¢/MCF)			
	Case II	Change	Case III	Change
1971	23 5	+ 0 1	23 5	+ 0.2
1975	26 2	+ 0 4	27 9	+ 0.5
1980	31 [illegible]	+ 0 9	37.8	+ 1 2
1985	39 8	+ 1 4	53.0	+ 1.9

TABLE 69

INCREASE OF 10 PERCENT IN OPERATING COSTS

	Oil "Prices" at 15% Return (S/Bbl)			
	Case II	Change	Case III	Change
1971	3.22	+0.07	3.23	+0.07
1975	3.63	+0.07	3.67	+0.07
1980	4.73	+0.08	4.95	+0.08
1985	6.18	+0.09	6.60	+0.10
	Gas "Prices" at 15% Return (¢/MCF)			
	Case II	Change	Case III	Change
1971	23.5	+0.2	23.5	+0.2
1975	26.2	+0.2	27.9	+0.2
1980	31.8	+0.3	37.8	+0.4
1985	39.8	+0.3	53.0	+0.5

TABLE 70

INCREASE OF 10 PERCENT IN ADDITIONAL OIL RECOVERY INVESTMENTS

	Oil "Prices" at 15% Return (S/Bbl)			
	Case II	Change	Case III	Change
1971	3.22	–	3.23	–
1975	3.63	+0.04	3.67	+0.04
1980	4.73	+0.09	4.95	+0.10
1985	6.18	+0.14	6.60	+0.16

Federal Taxation Policy

The base cases assumed that the existing taxation structure would continue unchanged. In order to determine the impact that changes in this policy area could have, parametric studies were run to evaluate changes in the statutory depletion rate, preference tax rate, job development credit, and implementation of an exploration and additional-recovery tax credit.

The results of these studies were expressed in terms of the effect on the average "prices" of oil and gas. It was also recognized that the method of analysis assumed that industry performs as a homogeneous group of corporate taxpayers with only domestic exploration and production activi-

TABLE 71

DOUBLING OF ENVIRONMENTAL, HEALTH AND SAFETY COSTS

Increased Revenue Requirements (Million Dollars per Year)

	Oil Operations		Gas Operations		Total	
	Case II	Case III	Case II	Case III	Case II	Case III
1971	60	60	22	22	82	82
1975	259	243	104	105	363	348
1980	501	451	188	190	689	641
1985	803	671	301	303	1,104	974

TABLE 72

NO NEW OFFSHORE LEASES

Oil Production (MMB/D)

	Case II	Change	Case III	Change
1971	9.1	-	9.1	-
1975	8.5	-0.3	8.1	-0.22
1980	9.2	-1.4	8.2	-1.04
1985	10.2	-2.3	8.6	-1.63

Marketed Gas Production (TCF/Yr)

	Case II	Change	Case III	Change
1971	20.0	-	20.0	-
1975	21.6	-0.7	20.2	-0.5
1980	21.1	-3.2	17.6	-2.1
1985	21.3	-5.5	16.2	-3.6

TABLE 74

DELAY OF ALL OFFSHORE LEASING FOR 5 YEARS

Oil Production (MMB/D)

	Case II	Change	Case III	Change
1971	9.1	–	9.1	–
1975	8.5	-0.3	8.1	-0.2
1980	9.2	-1.1	8.2	-0.8
1985	10.2	-0.4	8.6	-0.3

Marketed Gas Production (TCF/Yr)

	Case II	Change	Case III	Change
1971	20.0	–	20.0	–
1975	21.6	-0.7	20.2	-0.5
1980	21.1	-2.6	17.6	-1.6
1985	21.3	-1.6	16.2	-1.0

TABLE 73

DISCONTINUANCE OF OFFSHORE LEASING EXCEPT ON GULF COAST POST-1974

Oil Production (MMB/D)

	Case II	Change	Case III	Change
1971	9.1	-	9.1	-
1975	8.5	-0.3	8.1	-0.2
1980	9.2	-1.1	8.2	-0.8
1985	10.2	-1.5	8.6	-1.1

Marketed Gas Production (TCF/Yr)

	Case II	Change	Case III	Change
1971	20.0	-	20.0	-
1975	21.6	-0.7	20.2	-0.5
1980	21.1	-2.0	17.6	-1.3
1985	21.3	-1.6	16.2	-1.1

TABLE 75

DELAY OF PACIFIC OCEAN LEASING FOR 5 YEARS

Oil Production (MMB/D)

	Case II	Change	Case III	Change
1971	9.1	-	9.1	-
1975	8.5	-0.1	8.1	-0.1
1980	9.2	-0.3	8.2	-0.2
1985	10.2	-0.2	8.6	-0.1

Marketed Gas Production (TCF/Yr)

	Case II	Change	Case III	Change
1971	20.0	-	20.0	-
1975	21.6	-	20.2	-
1980	21.1	-0.1	17.6	-
1985	21.3	-0.1	16.2	-0.1

TABLE 76

ELIMINATION OF BONUS PAYMENTS OFFSHORE

	Oil "Prices" at 15% Return ($/Bbl)			
	Case II	Change	Case III	Change
1971	3.22	-0.01	3.23	- 0.01
1975	3.63	-0.23	3.67	0.24
1980	4.73	-0.70	4.95	0.80
1985	6.18	1.14	6.60	- 1.33
	Gas "Prices" at 15% Return (¢/MCF)			
	Case II	Change	Case III	Change
1971	23.5	-0.2	23.5	- 0.2
1975	26.2	-2.3	27.9	- 2.5
1980	31.8	-5.2	37.8	- 6.2
1985	39.8	-9.2	53.0	-12.3

ties. In reality, of course, this is not true; a sizable source of risk capital in the industry is from individual investors who have a higher tax rate than corporations. An attempt was made to investigate the sensitivity of this assumption by analyzing several cases using a 70-percent maximum individual tax rate.

Statutory depletion rates were investigated by comparing the current value of 22 percent to a range of 0 to 35 percent, as shown in Table 78.

Eliminating the depletion allowance would require an increase in the computed average oil "price" of 15 percent and gas "price" of 13 percent or, alternatively, it would have a much more substantial negative effect on the desirability of searching for oil and gas if the prices did not increase by these amounts. If gas prices are not permitted to increase because of contract or regulatory limitations, then an equivalent amount of revenue would have to be generated by increased oil prices. Increasing the depletion allowance to 35 percent would permit an 8-percent reduction in the average "price" of oil and a 7-percent reduction in the gas "price," or without price changes it would create a sizable incentive to develop new supplies.

As indicated in Table 79, the impact on the investor in the highest tax bracket is nearly twice that of a corporate taxpayer. Thus, he is very sensitive to such tax incentives in deciding where to make his investments. Many of these investors are the source of funds for the independent oil producers who play a substantial role in the discovery of new fields. Therefore, future discoveries

TABLE 77

REPLACEMENT OF CASH BONUS PAYMENTS WITH WORK PROGRAM

	Production							
	Oil (MMB/D)				Marketed Gas (TCF/Yr)			
	Case II	Change	Case III	Change	Case II	Change	Case III	Change
1971	9.1	–	9.1	–	20.0	–	20.0	–
1975	8.5	–	8.1	–	21.6	–	20.2	–
1980	9.2	+ 0.2	8.2	+ 0.1	21.1	+ 0.5	17.6	+ 0.4
1985	10.2	+ 0.4	8.6	+ 0.3	21.3	+ 1.2	16.2	+ 0.8
	"Prices" at 15% Return							
	Oil "Prices" ($/Bbl)				Gas "Prices" (¢/MCF)			
	Case II	Change	Case III	Change	Case II	Change	Case III	Change
1971	3.22	- 0.01	3.23	- 0.01	23.5	- 0.2	23.5	- 0.2
1975	3.63	- 0.23	3.67	- 0.24	26.2	- 2.2	27.9	- 2.4
1980	4.73	- 0.65	4.95	- 0.72	31.8	- 5.0	37.8	- 5.8
1985	6.18	- 0.93	6.60	- 1.14	39.8	- 8.7	53.0	- 11.3

TABLE 78

CHANGE OF STATUTORY DEPLETION RATES WITH 50-PERCENT TAX RATE

	Case II	Change to 35% Depletion	Change to 27.5% Depletion	Change to 0% Depletion	Case III	Change to 35% Depletion	Change to 27.5% Depletion	Change to 0% Depletion
	Oil "Prices" at 15% Return ($/Bbl)							
1971	3.22	- 0.26	- 0.09	+ 0.49	3.23	- 0.26	- 0.09	+ 0.49
1975	3.63	- 0.29	- 0.10	+ 0.55	3.67	- 0.29	- 0.10	+ 0.55
1980	4.73	- 0.37	- 0.13	+ 0.71	4.95	- 0.39	- 0.13	+ 0.74
1985	6.18	- 0.48	- 0.16	+ 0.92	6.60	- 0.52	- 0.17	+ 0.99
	Gas "Prices" at 15% Return (¢/MCF)							
1971	23.5	- 1.6	- 0.5	+ 2.7	23.5	- 1.5	- 0.5	+ 2.8
1975	26.2	- 1.8	- 0.6	+ 3.3	27.9	- 1.9	- 0.7	+ 3.5
1980	31.8	- 2.2	- 0.7	+ 4.0	37.8	- 2.6	- 0.8	+ 4.8
1985	39.8	- 2.7	- 0.9	+ 5.1	53.0	- 3.7	- 1.2	+ 6.8

TABLE 79

CHANGE OF 22-PERCENT STATUTORY DEPLETION RATE WITH 50-PERCENT AND 70-PERCENT INCOME TAX RATES

	50% Income Tax Rate			70% Income Tax Rate		
		Change 22% Depletion Rate to			Change 22% Depletion Rate to	
	Case III	35%	0%	Case III	35%	0%
	Oil "Prices" at 15% Return ($/Bbl)					
1971	3.23	-0.26	+0.49	3.59	-0.51	+1.20
1975	3.67	-0.29	+0.55	4.05	-0.57	+1.35
1980	4.95	-0.39	+0.74	5.58	-0.79	+1.86
1985	6.60	-0.52	+0.99	7.54	-1.06	+2.51
	Gas "Prices" at 15% Return (¢/MCF)					
1971	23.5	-1.5	+2.8	25.9	-3.1	+7.0
1975	27.9	-1.9	+3.5	30.6	-3.9	+8.7
1980	37.8	-2.6	+4.8	41.1	-5.2	+11.7
1985	53.0	-3.7	+6.8	58.8	-7.5	+16.9

will no doubt be heavily influenced by taxation policy.

The 1969 tax law established a minimum tax equal to 10 percent of the difference between the taxpayer's total preference items (such as statutory depletion) and his actual income tax liability. If this preference tax were either eliminated or raised to 20 percent, it would have the effect in 1985 of about a $0.17 per barrel change in the "price" of *all* oil and $0.01 per MCF for *all* gas. The impact on individual taxpayers would vary widely.

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Two types of tax credits were also evaluated. One is the 7-percent job development credit now in effect, and the other is a 12.5-percent credit for investment in exploration or additional recovery which has been proposed. The impact of both o these credits is essentially the same for Cases I and III and is shown in Table 80.

The job development credit is of increasing im portance in a growing industry; an exploratio and additional recovery tax credit could provide significant incentive to develop new oil and ga supply.

Another parametric study was made to evaluat the impact of capitalizing intangible drilling cost as depreciable investment for tax purposes. Th

TABLE 80

CHANGE OF TAX CREDITS—
50-PERCENT TAX RATE

	Case II	Change Due to Removing 7% Job Development Credits	Change Due to Implementing 12.5% Exploration and Additional Recovery Credits
	Oil "Prices" at 15% Return ($/Bbl)		
1971	3.22	+0.06	-0.17
1975	3.63	+0.08	-0.24
1980	4.73	+0.11	-0.30
1985	6.18	+0.15	-0.38
	Gas "Prices" at 15% Return (¢/MCF)		
1971	23.5	+0.3	-1.4
1975	26.2	+0.2	-1.5
1980	31.8	+0.3	-2.2
1985	39.8	+0.3	-2.6

TABLE 81

CAPITALIZATION OF INTANGIBLE DRILLING COSTS
15-PERCENT RATE OF RETURN
(Million Dollars per Year of Increased Revenue Requirements)

	Oil		Gas		Total	
	Case II	Case III	Case II	Case III	Case II	Case III
1971	633	616	352	351	985	967
1975	620	530	279	280	899	810
1980	451	318	236	238	687	556
1985	332	227	92	92	424	319

TABLE 82

TOTAL AVAILABLE OIL
(MMB/D)

		Projected											
		Case I			Case II			Case III			Case IV		
	Actual 1970	1975	1980	1985	1975	1980	1985	1975	1980	1985	1975	1980	1985
Conventional Petroleum Liquids	11.3	10.2	13.6	15.5	10.2	12.9	13.9	9.8	11.6	11.8	9.6	8.9	10.4
Synthetic Liquids													
From Coal	–	–	0.1	0.7	–	–	0.1	–	–	–	–	–	–
From Oil Shale	–	–	0.2	0.8	–	0.1	0.4	–	0.1	0.4	–	–	0.1
Oil Imports	3.4	7.2	5.8	3.6	7.4	7.5	8.7	8.5	10.6	13.5	9.7	16.4	19.2
Total Supply*	14.7	17.5	19.6	20.5	17.6	20.5	23.1	18.3	22.3	25.8	19.3	25.3	29.7

* Totals may not agree due to rounding.

effect of this change would be to increase the revenue required by the industry by the amounts shown in Table 81 in order to maintain the same after-tax capital available for drilling, assuming a 50-percent tax rate for the industry. The initial impact is very significant and in effect would increase the after-tax drilling costs by about one-third. The effect upon industry earnings diminishes in later years as a depreciable base is built up. However, any new investor will always bear the full impact since he has no depreciable base with which to start.

TABLE 83

TOTAL AVAILABLE GAS
(TCF/YEAR)

		Projected											
	Actual	Case I			Case II			Case III			Case IV		
	1970	1975	1980	1985	1975	1980	1985	1975	1980	1985	1975	1980	1985
Lower 48													
Onshore	22.2	18.7	17.3	17.1	18.5	16.5	15.2	17.6	14.3	12.0	17.4	13.1	9.6
Offshore		4.9	6.9	9.1	4.8	6.3	7.8	4.3	4.8	5.5	4.1	4.0	3.6
Alaska, North Slope	–	–	1.4	3.3	–	1.3	2.7	–	1.1	2.2	–	–	1.3
Alaska, South	0.1	0.2	0.2	1.1	0.2	0.2	0.9	0.2	0.2	0.6	0.2	0.2	0.4
Total Conventional* (Wellhead Production)	22.3	23.7	25.9	30.6	23.6	24.3	26.5	22.0	20.4	20.4	21.8	17.3	15.0
Synthetic Gas													
From Coal	–	–	0.6	2.5	–	0.4	1.3	–	0.4	1.3	–	0.2	0.5
From Liquids	–	0.6	1.3	1.3	0.6	1.3	1.3	0.6	1.3	1.3	0.6	1.3	1.3
Gas from Nuclear Stimulation	–	–	0.2	1.3	–	0.1	0.8	–	0.1	0.8	–	–	–
Imports													
LNG	†	0.2	2.3	3.2	0.2	2.3	3.4	0.2	2.3	3.7	0.2	2.3	3.9
Pipeline	0.8	1.0	1.6	2.7	1.0	1.6	2.7	1.0	1.6	2.7	1.0	1.6	2.7
Total Supply*	23.1	25.5	31.9	41.6	25.4	30.0	36.0	23.8	26.1	30.2	23.6	22.7	23.4

* Totals may not agree due to rounding.
† Less than 10 billion cubic feet

REMARKS OF SENATOR JACKSON INTRODUCING S. 2885

[From the Congressional Record, Jan. 24, 1974]

(*By Mr. Jackson (for himself, Mr. Magnuson, Mr. Bible, Mr. Biden, Mr. Inouye, Mr. Chiles, Mr. Ribicoff, Mr. Metzenbaum, Mr. McGovern, Mr. Eagleton, and Mr. Mondale)*)

S. 2885. A bill to amend section 4 of the Emergency Petroleum Allocation Act of 1973 to direct the President to establish ceiling prices on petroleum and related goods. Referred to the Committee on Interior and Insular Affairs.

Mr. JACKSON. Mr. President, in December 1972, the National Petroleum Council, an advisory body composed of representatives of the major oil companies, presented to the Secretary of the Interior and the Congress a report on U.S. energy policy. The NPC report estimated that to achieve the greatest feasible level of domestic self-sufficiency, the domestic price of crude oil would have to rise from $3.18 per barrel in 1970 to $3.65 in 1975. In August 1972, the Independent Petroleum Association of America testified before the Committee on Interior and Insular Affairs that a domestic price of $4.10 per barrel would be adequate to assure the United States 100 percent self-sufficiency by 1980.

These projections were in constant dollars so to be fair and to take account of inflation, the NPC price would have to be increased to $4.35 and the IPAA price would have to be $4.55 today.

These were the prices domestic industry said it needed only a little over a year ago to achieve the maximum level of domestic self-sufficiency.

In his statement to the Finance Committee on January 23, 1974, Deputy Secretary Simon estimated that the long term supply price of crude oil—the level needed to bring supply and demand into balance, that is, to eliminate the shortage—is "in the neighborhood of $7 per barrel within the next few years." Any price higher than that creates, in Secretary Simon words:

> A "windfall"—a price to producers which is more than producers could have anticipated when investments were made and more than that requested to produce all that we can in fact expect to be supplied.

Notwithstanding Mr. Simon's insight in this matter, the Federal Energy Office and the Cost of Living Council have allowed a price for "old" oil of $5.25—a level for flowing oil wells which is far in excess of the industry's own estimate of the long-run supply price, and well in excess of what producers could have anticipated. More important, this price increase on old or flowing oil cannot have a significant impact upon the supply of oil or even provide any increased incentive for the production of new oil.

Mr. Simon's office has totally decontrolled the prices of the so-called "new oil," together with an equivalent amount of old oil, so-called "released" oil. This oil, plus oil from stripper wells, is now selling at an average of $10.35 per barrel—more than twice the level industry estimated a year ago to be necessary for maximum self-sufficiency, and about 50 percent higher than the level Mr. Simon himself believes could be useful in eliciting new supply.

Profits of the seven largest oil companies increased by 46 percent in the first three quarters of 1973 over the same period of 1972, on a sales volume that increased only 6 percent. There is every indication that oil company profits are now running at nearly twice the level of a year ago. Top company officials, in testimony this week before the Permanent Investigations Subcommittee, acknowledged that the main reason for the surge in profits was the increase in prices of the crude oil that is exempt from price control.

No one in the administration has offered any serious justification for either the jump in old oil prices or for decontrolling new oil. What seems to be at work is a continuing conviction that the way to eliminate the fuel shortage is to increase prices—by taxes or otherwise—high enough to limit demand by pricing gasoline and fuel oil beyond the reach of many Americans. This philosophy is apparent in the administration's so-called windfall profits tax proposal, which is not a profits tax at all, but an "excise" tax on crude oil that would be passed directly on to consumers.

I am today introducing a bill which would amend the Emergency Petroleum Allocation Act to require ceiling prices on all crude oil, refined petroleum products, and related goods. These ceilings would prevent price increases in excess of those that would actually increase long-run supply and diminish long-run demand.

Ceiling prices would be limited to a dollar-for-dollar cost passthrough, except for the sole purpose of encouraging increased domestic exploration and production of crude oil or investment in new refining and transportation capacity. Any such increase would have to be accompanied by a detailed statement of the extent and the means by which any price increases which are greater than a passthrough of cost can be reasonably expected to increase supply.

My intention and expectation in submitting this amendment is to roll back the price of domestic crude oil and to establish a ceiling for any crude, no higher than Mr. Simon's $7 per barrel. Moreover, I would expect that, under this legislation, any price above $4.50 per barrel would have to be justified in close detail as providing a significant increase in long-term supply.

LETTER TO SENATOR HENRY M. JACKSON FROM VINCENT M. BROWN, EXECUTIVE DIRECTOR, NATIONAL PETROLEUM COUNCIL, FEBRUARY 1, 1974

National Petroleum Council,
February 1, 1974.

Hon. Henry M. Jackson,
U.S. Senator, U.S. Senate,
Washington, D.C.

Dear Senator Jackson: I have read your remarks which appear in the January 24, 1974, Congressional Record page S389 in which you introduced for yourself and others Senate Bill No. 2885 to amend section 4 of the Emergency Petroleum Allocation Act of 1973 to direct the President to establish ceiling prices on petroleum and related goods. The bill was referred to the Committee on Interior and Insular Affairs. I would appreciate your insertion of this letter in the record of testimony or hearings held in connection with this proposed piece of legislation.

Your use of the domestic crude oil "price" in 1975 of $3.65 per barrel, as it appears in the study, is completely out of context. In addition, your citation of the NPC report to support your conclusion that "these were the prices domestic industry said it needed only a little over a year ago to achieve the maximum level of domestic self-sufficiency" is patently incorrect. The report contains no such finding or conclusion. As a matter of fact it stated, "Even in Case I (the most optimistic supply case), oil imports more than double between 1970 and 1975" and that even by 1985, there would be a necessity to import 18 percent of our total oil supply under the Case I conditions.

As clearly and urgently stated in the NPC report, "Price increases alone will not assure substantial increases in the exploration for and development of oil and gas supplies. They must be accompanied by *reasonable*, *consistent* and *stable* governmental policies specifically designed to encourage the development of additional domestic oil and gas production. Policy issues of particular importance include leasing of government lands, environmental conservation, taxation, natural gas price regulation and oil import quotas."

The National Petroleum Council's U.S. Energy Outlook study was an extremely technical study utilizing the judgment, experience and training of approximately 1,000 highly qualified professional people from both government and industry, including energy experts from outside the oil and gas industries. Throughout the two years of the study, careful and objectives analysis was applied to all phases of the work to provide the best possible projection of energy alternatives available to this country. This same attitude toward accuracy and thoroughness is also apparent in the numerous reports which these same professionals prepared on each facet of this study. Of particular significance are definitions and descriptions of terms and methods pro-

vided by the authors to assure clarity and proper use of the results reported. It is unfortunate when these are ignored.

In December 1972, the NPC released a Summary Report of the U.S. Energy Outlook study, summarizing massive supply calculations that were developed for each of the primary fuels. The approach was to construct four principal cases to cover the range of reasonable supply projections. In designing the four cases, a number of assumptions were made regarding physical, economic and government policy factors. For example:

Case 1.—This is the high end of the calculated supply range for each fuel and would be difficult to attain. It would require vigorous effort fostered by *early* resolution of controversy about environmental issues; ready availability of government land for energy resource development; adequate economic incentives; and a higher degree of success in locating current undiscovered resources than has been the actual case in recent years.

Case 4.—This is the low end of the range of supply availability and repesents a likely outcome if disputes of environmental issues continue to constrain growth and output of all fuels; if government policies prove to be inhibited; and if oil and gas exploratory successes do not improve over recent levels.

Cases 2 and 3.—Represent two intermediate appraisals, with Case 2 postulating greater improvements in finding rates for oil and gas, and quicker solution to problems in fabricating and installing nuclear power plants than does Case 3.

Many variables influence the supplies of domestic oil and gas that can be developed and the revenues required to yield acceptable returns on investment. Two of the most significant are the finding rate (volume of oil and gas found per unit of exploratory effort) and the drilling rate (three different ones were assumed in the study). The three drilling activity projections, when combined with the two finding rate assumptions, result in a set of four principal cases—each with projected reserve additions, production rates, costs and required average wellhead revenues to achieve specified rates of return. None of these projections, because of the future uncertainties in the variable factors, can be treated as forecasts.

Page 1 of the report states this clearly as follows:

> As a starting point, this procedure required the development of *assumed* ranges of activity levels and, where relevant, success ratios. These were translated into production volumes, costs and "prices" needed to provide reasonable returns on investment. The methodology was not designed to develop activity levels or resulting supplies based on assumed prices or to quantify the incentives needed to realize the assumed levels of activity. These incentives, which are not measurable within calculated prices, include such important motivational factors to an investor as the anticipated future economic and political climate.

May I emphasize, as also stated on page 1 of the NPC report, that as used in this study, "price" does not mean a specific selling price as between producer and purchaser and does not represent a future

market value. The term "price" refers generally to economic levels which would, on the basis of the four cases analyzed, support given levels of activity for the particular fuel.

With respect to economic incentive, the report states:

> The most effective economic incentive would be to allow prices to increase to the level at which the industry can attract and internally generate the risk capital needed to expand activity to its maximum capability. This requires both a fair return on total investment (e.g., return on net fixed assets), as well as the anticipation of attractive returns on current and future investments.

The method of computing the required oil "price" in the four cases results in an *average* value for both the "old" oil discovered before 1971 and the "new" oil found during 1971–1985 period.

The table below shows the average required prices for the Lower 48 States for oil (in 1970 constant dollars) for all four supply cases to result in a 15 percent rate of return on *total* investment, not just the new investment. For your information, I have added a column showing the "prices" if an inflation factor of 4 percent per annum is added.

SUMMARY OF AVERAGE REQUIRED PRICES PER BARREL OF OIL, LOWER 48 STATES

[1970 actual—$3.18; current dollar with 4 percent per year inflation]

	Case I		Case II		Case III		Case IV	
	1970	Current	1970	Current	1970	Current	1970	Current
1975	$3.65	$4.45	$3.63	$4.43	$3.67	$4.48	$3.57	$4.35
1980	4.90	7.25	4.73	7.00	4.95	7.33	4.39	6.50
1985	6.69	12.00	6.18	11.12	6.60	11.88	5.28	9.50

Thus, average "prices" in 1985 range from $5.28 to $6.69 per barrel up from $3.18 in 1970 (or with inflation added, the average prices in 1985 for oil would range from $9.50 to $12.00 per barrel). I note you cited only the 1975 price for Case I. Since the lead times inherent in finding and developing new oil and gas supplies range from 3 to 8 years, only by 1985 were significant increments in domestic oil supplies attained.

Under the most optimistic supply conditions (Case I) and given a demand growth rate of 4.2 percent per year, domestic oil might provide 28 percent of total energy requirements in 1985, which would still represent a decline from 31 percent in 1970. If present trends continue (as in Case IV), domestic oil would only provide 17 percent of total requirements in 1985.

The NPC study is a long-range fuel supply study, and 1975 by itself, was not considered signficant for purposes of drawing major conclusions. If conclusions are to be drawn, they should be for the whole period 1971–1985, with particular focus on 1985.

In none of the cases for *any* year would domestic self-sufficiency in oil be attained, and only by 1985 could a reasonable or feasible level of domestic self-sufficiency in energy be achieved.

Energy imports in 1970 were abount 12 percent of the U.S. energ supply. In *all* cases, energy imports increase *sharply* between 197 and 1975. Imports as a percent of total energy supply are:

	1970	1975	1980	198
Case I	12	20	16	1
Case II	12	20	19	2
Case III	12	23	26	2
Case IV	12	26	38	3

Even in Case I, *oil* imports more than double between 1970 an *1975*. Required imports in *1985* range from 19.2 MMB/D in Case I to 3.6 MMB/D in case I.

	1970	1975	1980	198
Oil imports as a percent of total oil supply:				
Case I	26	42	30	1
Case II	26	43	37	3
Case III	26	51	66	6
Case IV	26	51	66	6
Oil imports (million barrels per day):				
Case I	3.4	7.2	5.8	3.
Case II	3.4	7.4	7.5	8.
Case III	3.4	8.5	10.6	13.
Case IV	3.4	9.7	16.4	19.

It is my desire herein to clarify for the record what the NPC study on U.S. Energy Outlook actually concluded. I understand that copies of all our energy reports and supporting documents have been made available to the members of the Senate Committee on Interior and Insular Affairs and its staff.

Sincerely yours,

VINCENT M. BROWN,
Executive Director.

MEMORANDUM TO MEMBERS OF THE SENATE INTERIOR COMMITTEE FROM ARLON R. TUSSING, CHIEF ECONOMIST, FEBRUARY 4, 1974

[Memorandum, February 4, 1974]

To: Members of the Committee on Interior and Insular Affairs and of the House-Senate Conference Committee on the Energy Emergency Act.

From: Arlon R. Tussing, chief economist, Committee on Interior and Insular Affairs.

Re National Petroleum Council's "Required Prices for Crude Oil".

Senator Jackson and other members have recently cited the December 1972 study by the National Petroleum Council (NPC) (*U.S. Energy Outlook*) as evidence that the producing industry only a year ago, regarded crude oil prices in the range of $3.50 to $4.50 per barrel as adequate to support the maximum practical level of exploration and development. The members have singled out the attached Table 15 of the NPC report, *U.S. Energy Outlook*, which indicates that a price of $3.65 would be "required" in 1975 to support the NPC's most optimistic scenario (Case I). Because the latter figure was given in 1970 dollars, the equivalent price today would be about $4.35, which is very close to the average price of "old" oil before the increase authorized by FEO in December.

Vincent M. Brown, Executive Director of the NPC, has submitted the attached letter for the record, protesting this use of the NPC study. He wrote Senator Jackson:

> Your use of the domestic crude oil "price" in 1975 of $3.65 per barrel, as it appears in the study, is completely out of context. In addition, your citation of the NPC report to support your conclusion that "these were the prices domestic industry said it needed only a little over a year ago to achieve the maximum level of domestic self-sufficiency" is patently incorrect. The report contains no such funding or conclusion.

Mr. Brown's criticism addresses two issues (1) the structure of the NPC's economic model and (2) the definition of "price" used in the tables.

In simple terms, the NPC's methodology for each of four "Cases" (and a number of sub-cases) is as follows:

(1) A specific drilling rate is assumed;

(2) The cost of this much drilling is the investment required;

(3) A specific "success rate," the ratio of reserve additions to drilling effort, is assumed;

(4) The rate of production in future years is inferred from the reserves added; and finally,

(5) Average crude oil prices were calculated for each year, which would give revenues equal to a given "return" (e.g., 15 percent) on the industry's invested capital figures.

Mr. Brown's protest is correct to the following extent: the NPC's naive economic model was not explicitly "designed to develop activity levels [drilling rates, etc.] or resulting supplies based on assumed prices or to quantify the incentives needed to realize the assumed levels of activity." (p. 1 of his letter) In other words, its formal results were never designed to be useful in evaluating such factors as price controls, taxes, the rate of OCS leasing, or other policies that might *affect* either the drilling rate or the success rate. These rates were, on the contrary, already given as *assumptions* of the study.

An economic model designed to estimate the effectiveness of various policies toward the oil industry would have to differ from the NPC model in at least two respects: (1) it would have to recognize that the success rate *depends upon* the drilling rate (because of the tendency to explore and develop the best available prospects first), and (2) it would use a discounted cash flow rate of return concept rather than the balance sheet concept used by the NPC.

Notwithstanding the inappropriateness of its methodology for evaluating many important public policy questions, the NPC's report, *U.S. Energy Outlook*, did not hesitate to draw quantitative conclusions about prices, taxes and leasing rates *as if these were logical inferences from the study.* The very captions of the tables seem chosen to convey this impression. The table which Senator Jackson cited was labeled "Average Required 'Prices' ". The attached supporting table (no. 660) from the background report to *U.S. Energy Outlook*, "Oil and Gas Availability," is labeled "Average Unit Revenue Required Per Barrel of Crude Oil (Dollars Per Barrel)."

The text even more explicitly attempts to lead the reader to policy conclusions purportedly based upon what Mr. Brown characterizes as the Council's "extremely technical study utilizing the judgment, experience and training of approximately 1,000 highly qualified professional people from both government and industry, including energy experts from outside the oil and gas industry." The following are explicit claims in the NPC report:

> "For each fuel, the four principal supply cases estimated the average unit revenues or prices required to support assumed ranges of activity levels, given an assumed range of investment returns. These analyses indicate that real energy prices of domestic fuels at the well head or mine must rise significantly by 1985. Since the prices cited for the fuels do not consider differences in quality, distribution costs or use characteristics, the prices calculated in this study cannot be meaningfully compared with each other. The projected range of percentage increases in average prices required to 1985 (in terms of 1970 dollars) over 1970 for individual fuels is indicated below:
>
> Oil at the wellhead: up 60 to 125 percent
> Gas at the wellhead: up 80 to 250 percent
> Coal at the mine: up about 30 percent
> U_3O_8: up about 30 percent.
>
> "The above ranges would imply an average annual increase in fuel prices of 2 to 9 percent, though the rate of increase would not necessarily be uniform throughout the period to

1985 and would not be the same for each fuel. These are increases in real costs over and above inflation.

"The required prices calculated indicate a need for a sharp reversal of the declining real price trends that have been experienced for the last several years. Declining prices have reduced the attractiveness of this high-risk industry as is evidenced by the decline in both drilling effort and in reserve additions resulting from new exploration."

The NPC model's validity (or lack of validity) for measuring the effects of changes in tax policy depends on exactly the same factors as its validity for price analysis. Specifically, in Mr. Brown's words, the model was not designed ". . . to quantify the incentives needed to realize the assumed level of activity." Yet, the report's narrative did not shrink from making quantitative judgments about the impact of tax reform:

"Long-established tax provisions for the extractive industries have historically promoted the development of energy supplies. These tax features deal with percentage depletion applicable to coal, uranium, oil, gas, oil shale and geothermal steam, and those permitting current deductions of intangible costs for oil and gas. Adverse changes in such tax provisions would prove expensive for the Nation because they would reduce supplies and lead to higher costs and prices. For instance, complete removal of the statutory depletion allowance would necessitate an immediate "price" increase on the order of $0.50 per barrel for all oil and $.03 per thousand cubic feet (MCF) for gas; by 1985 it would necessitate increases of $0.90 to $1.00 per barrel and $0.05 to $0.07 per MCF in order to maintain a return on investment sufficient to generate and attract the capital needed to provide the supply projected. These price increases are over and above the increased prices indicated for the particular fuel cases in 1985 due to higher investment and operating costs."

Mr. Brown vigorously objects to the Senators' use of the NPC report to support the case for price rollbacks, but as long as the numbers generated by its model appeared to support price *increases* (rather than rollbacks) the Council was willing, notwithstanding the many limitations it recognized in its model, to have readers think that these numbers were meaningful for a quantitative assessment of price policies.

"The most effective economic incentive would be to allow prices to increase to the level at which the industry can attract and internally generate the risk capital needed to expand activity to its maximum capability. This requires both a fair return on total investment (e.g., return on net fixed assets), as well as the anticipation of attractive returns on current and future investments.

During the last 10 to 15 years, real prices of oil and gas at the wellhead have declined while real costs have been increasing. As a result, both drilling activity and addition of new reserves have declined rapidly. Assuming a 15-percent

annual rate of return in constant 1970 dollars, 1985 average oil prices may have to range from $5.06 to $7.21 per barrel, and 1985 average gas prices may have to range from $0.31 to $0.59 per MCF to support the activity levels assumed (Cases IA and IVA). If prices for gas found prior to 1971 are prevented from increasing by regulatory or contractual restrictions, the required price in 1985 for gas found after 1970 would be on the order of 30 to 50 percent greater than the average prices calculated.

Even a continuation of drilling activity along the current declining trend will require price increases of about $2.00 per barrel and $0.15 per MCF by 1985 if the petroleum industry is to realize a 15-percent return on its net fixed assets."

In fairness to the NPC, no model or methodology can answer all questions equally well, and the NPC report is hedged with sufficient disclaimers to deter any careful reader from taking most of its projections, above all its price projections at face value.

Senator Jackson did not, in his statement quoted by Mr. Brown, assert that the NPC "price" estimates were correct. *He cited them as evidence of the levels which the oil industry thought barely one year ago would be necessary to support a sharp upturn in domestic investment and production.* These figures were used by the NPC for exactly that purpose— to propagandize for higher prices.

Taken precisely in the context of the whole NPC report, which was used by the Council to underpin the industry's defense of higher prices, oil import quotas, and tax preferences, it is entirely proper to say, as Senator Jackson did, that "these were the prices domestic industry said it needed only a little over a year ago. . . ."

TABLE 15.—AVERAGE REQUIRED PRICES FOR OIL AND GAS—1970 CONSTANT DOLLARS

	Actual [1]		Projected at 15 percent return on net fixed assets		
	1965	1970	1975	1980	1985
HIGH FINDING RATES					
Crude oil price (dollars per barrel):					
Case I	3.26	3.18	3.65	4.90	6.69
Case II	3.26	3.18	3.63	4.73	6.18
Gas field price (cents per thousand cubic feet):					
Case I	17.8	17.1	26.7	33.7	43.6
Case II	17.8	17.1	26.2	31.8	39.8
LOW FINDING RATES					
Crude oil price (dollars per barrel):					
Case III	3.26	3.18	3.67	4.95	6.60
Case IV	3.26	3.18	3.57	4.39	4.28
Gas field price (cents per thousnad cubic feet):					
Case III	17.8	17.1	27.9	37.8	53.0
Case IV	17.8	17.1	26.6	31.6	38.7

[1] Bureau of Mines' actual data, unadjusted for rate of return.

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"ENERGY SELF-SUFFICIENCY: AN ECONOMIC EVALUATION"

Complete independence from foreign energy supplies is a form of insurance against energy disruption or price increase which the U.S. could purchase only at very high cost. Other, less costly, ways to achieve that goal remain to be exploited. Here is a summary of U.S. energy policy alternatives to 1980, the result of an intensive study of energy technology and economics by members of the M.I.T. Energy Laboratory, colleagues, and consultants

Energy Self-Sufficiency: An Economic Evaluation

The Policy Study Group of the M.I.T. Energy Laboratory:
* Morris A. Adelman, Professor of Economics, M.I.T.
Robert E. Hall, Associate Professor of Economics, M.I.T.
Kent F. Hansen, Professor of Nuclear Engineering, M.I.T.
J. Herbert Hollomon, Professor of Engineering and Director of the Center for Policy Alternatives, M.I.T.
* Henry D. Jacoby, Professor of Management, M.I.T.
* Paul L. Joskow, Assistant Professor of Economics, M.I.T.
* Paul W. MacAvoy, Professor of Management, M.I.T.
* Herman P. Meissner, Professor of Chemical Engineering, Emeritus, M.I.T.
* David C. White, Ford Professor of Engineering and Director of the Energy Laboratory, M.I.T.
* Martin B. Zimmerman, Research Associate in Management, M.I.T.

* Principal authors of this report.

In Association with:
Donald B. Anthony, Department of Chemical Engineering, M.I.T.
Joseph Bell, School of Law, Duke University
Edward Erickson, Department of Economics, North Carolina State University
Richard Gordon, College of Earth and Mineral Sciences, Pennsylvania State University
Robert P. Greene, Energy Laboratory, M.I.T.
James Gruhl, Energy Laboratory, M.I.T.
Jerry A. Hausman, Department of Economics, M.I.T.
Edward Hudson, Department of Economics, Harvard University
Dale Jorgenson, Department of Economics, Harvard University
William A. Litle, Department of Civil Engineering, M.I.T.
Richard Mancke, Department of Economics, University of Michigan
James W. Meyer, Energy Laboratory, M.I.T.
Charles M. Mohr, Department of Chemical Engineering, M.I.T.
James Sloss, Department of Civil Engineering, M.I.T.
Robert Spann, Department of Economics, Virginia Polytechnic Institute and State University

Foreword: The Report and Its Sources

The report that begins on the opposite page had its genesis at least four years ago, when a number of members of M.I.T. faculty became concerned with this nation's ever-growing use of energy; given limits on domestic supplies, it was evident even then that changes in the extent and nature of energy availability, however they came, would soon deeply and broadly affect the American economy.

Analysis of the energy situation was expanded in M.I.T. classrooms and laboratories, with the result that a great deal of new work was begun in many fields of technology, management, and the social sciences. To crystallize and provide a focus for the interdisciplinary interests which were clearly emerging, the Institute established an Energy Laboratory in 1972; its Director is David C. White, Ford Professor of Engineering.

Thus by the fall of 1973, when it became clear that the forecasts of energy-induced dislocations might be fulfilled far more quickly than most of us had expected, the Institute had in being an informed and effective working group with an understanding of energy issues ranging from economics, marketing, and policy problems to technological options and environmental issues. The M.I.T. administration believed this to be a uniquely informed, independent resource, and we accordingly proposed early this year that the Energy Laboratory's Policy Study Group turn its attention to the concept of "Project Independence"—the effort to develop and exploit U.S. energy resources so intensively that by 1980 the nation would no longer need to depend on imported fuels. The implications of that effort—the question of whether the goal could be achieved and, if so, the price its achievement might entail for the nation—became the focus of a major M.I.T. study, of which the following is the full, final report. The Group and its consultants from other universities have been greatly encouraged and helped by the interaction of many government agencies whose staffs shared data and reviewed or helped refine the interim results.

The report which follows does not propose to show how the nation can solve its energy problems. Its central theme is to study the responsiveness of today's complex energy system to those changes in the supply of fuels and in the demand for energy which are in fact possible by 1980 through present and foreseeable technology, and the effect on both these of changes in the prices of fuel and of energy. The best of forecasters is humbled by questions in this realm, and yet the issues now before the country demand that our discussion of policies and alternatives be based on the most competent and disinterested understanding of just these interrelationships. The purpose of this report, and of M.I.T. in sponsoring it, is to help achieve that goal.

Behind every energy bottleneck and in every future decision stand serious societal issues—nuclear power plant safety, environmental protection, and many others. Such issues, though both appropriate and important to the debate which is now in progress throughout the nation, are beyond the scope of this report.

—Albert G. Hill
Vice President for Research, M.I.T.

Overview of the Study

The United States is dedicated to a policy of independence from foreign supplies of energy. Under the name "Project Independence," goals have been set which call for complete self-sufficiency by the end of the decade, to free the nation from the threat of disruption in oil imports and from sharp price increases—or a higher price level—for oil and gas from abroad. It has been stated that the first priority for the new Federal Energy Agency will be "to work with other government agencies to prepare a comprehensive plan to make the nation self-sufficient in energy by 1980."[1]

This study seeks to evaluate the state of the economy under energy self-sufficiency. On the assumption that the United States meets all its energy demands from internal sources by 1980, forecasts are made of the market-clearing prices for various forms of energy—the prices at which supply and demand will be in equilibrium. The results indicate that prices of $10.00 to $12.00 per barrel (oil-equivalent) will be necessary to bring forth enough additional supplies of fossil fuels to satisfy demands in domestic energy markets by that time. This means that even if concerted efforts were made to remove the bottlenecks that now exist in these markets (such as federal price regulation of natural gas), there would have to be another round of price increases for consumers as great as that experienced in 1973-1974.

In short, self-sufficiency, as a form of "insurance" against disruption or price increase, will be purchased at a very high cost. The curtailment of imports acts to replace a temporary embargo, or a threat of an embargo, with a permanent embargo that increases prices beyond present levels.

There are other ways to approach the problem of U.S. dependence on foreign sources. One way involves the use of flexible tariffs or quotas to hold the oil price at a high level that would reduce imports. This method is examined in detail, and it is concluded that the current oil price is high enough to extract present domestic oil and gas reserves with great efficiency. A still higher price would have only a marginal effect on exploration production over the next few years within the United States. Current prices also provide ample incentives for coal production. However, it might require a doubling of price to provide enough incentive to bring about large-scale commercial development of synthetic fuels in the near future—and their development is not sufficiently promising of large supplies to justify such high prices *for all energy.* It is concluded, therefore that the import price now prevailing is high enough, and little is to be gained by raising it more. The use of tariffs or quotas to increase prices should not be adopted as an instrument of policy at this time.

For many of the same reasons, there is no need at present to provide a firm floor under present prices. Most industry experts seem to believe that there are incentives for adequate domestic supply expansion at prices as low as $7.00 per barrel, so there is little need to set a price floor under current conditions. Should estimates of supply costs change, this judgment would have to be reconsidered.

Special price policies should be developed for the synthetics industry, though. The best way to bring forth significant supplies of "syngas," "syncrude," methanol, or shale oil in the *late* nineteen-eighties would be to identify these as a special class of new energy sources and provide specific price guarantees for such output. The federal government ought to offer to purchase oil, gas, or methanol from synthetic commercial plants at a price agreed upon by negotiation or resulting from competitive bids.

Security can be provided against import disruption by the introduction of radically new import policies. One important element would be an import storage program by which a stockpile of crude oil beyond normal inventories would be maintained as a hedge against significant and lengthy embargoes. The maintenance of a stockpile to guard against a one-year cutoff of 2 million barrels per day of imports would cost about $996 million per year. If the government required that it be provided by the oil industry, the cost of oil delivered to consumers would rise by no more than 26¢ per barrel or two thirds of a cent per gallon. Other elements of a foreign purchase program are not worked out in this study, but the general thrust of the scheme would be to purchase oil from abroad when the sources are forecast to be free from "bloc" policies to restrict supplies. While independence can be partially achieved a number of different ways, the least-cost solution will most likely involve a combination of several specific import and subsidy schemes, rather than a complete cessation of imports.

[1] *New York Times,* May 8, 1974, p. 72.

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One: The Critical Uncertainties

In the wake of the recent Mideast war and the disruption of international petroleum markets, a commitment has been made to free the United States from dependence on insecure and expensive foreign sources of energy. The program to achieve this objective has been termed "Project Independence"; as currently defined, it implies a goal of domestic self-sufficiency in energy by 1980. Under this definition, Project Independence raises issues that cut across the full range of government and corporate policies in the energy sector of the economy. There are implications for controls of domestic prices, controls of imports, for incentives to domestic production, and for the development of new technologies. Most important, there are implications for the prices which American consumers will pay for energy or for products using energy—which in turn embrace the full range of goods and services comprising the U.S. Gross National Product.

The central concern is whether Project Independence can result in domestic supply and demand equilibrium at socially tolerable prices. Examination of the issues requires a comparison of the likely market-clearing prices for energy products under two conditions: complete self-sufficiency and the absence of self-sufficiency, which implies some degree of net import demand. Such forecasts are extremely difficult to make at the present time, because of critical and in some cases irreducible uncertainty in five sets of factors.

□ *One: Responsiveness of Domestic Supply and Demand to Price Changes*. There is now available a wide range of estimates of expected demand and supply for energy in the early nineteen-eighties. Some studies show the market for most energy products clearing by 1980 with no net imports (or nearly none) on the basis of an (equivalent) oil price of $6.00 to $7.00 per barrel. Other studies indicate that the market-clearing price will rise as high as $15.00 per barrel before self-sufficiency is attained.

The desirable mix of policy measures to achieve Project Independence depends upon whether the price is $6.00 or $15.00 per barrel, and the economic costs and benefits of Project Independence are greatly different over this range of outcomes. If the economy were to adjust smoothly to exclusively domestic supply at $6.00 per barrel, then the desired Government policy would be to remove unnecessary bottlenecks to the adjustment process and otherwise do nothing. But if a price of $15.00 is required to clear markets with exclusively domestic supplies, then the policy of doing nothing would have undesirable income distribution implications and perhaps unacceptable effects on the rate of growth and employment of resources in the domestic economy. Therefore, it is extremely important to reduce the uncertainties in predictions of the 1980 equilibrium price, insofar as it is possible to do so.

The approach here is to combine studies of supply for specific energy resources with overall demand forecasts to estimate "total supply and total demand" for energy in the domestic economy. The studies used imply different levels of responsiveness of supply and demand to price, and the resulting estimates define a range of prices likely under energy self-sufficiency. Sections 3 through 7 are devoted to specific fuels, and the overall supply and demand estimates for 1980 are summarized in Section 2.

□ *Two: World Oil Price*. The price of oil imports to the United States is now well over $9.00 per barrel. Evaluation of Project Independence requires an estimate of this price in the future, because the alternative to self-sufficiency is to continue to purchase supplies from international oil markets. If the world oil price were greatly reduced, the cost of Project Independence—in terms of our inability to purchase cheap supplies abroad—would be greatly increased.

There is little basis upon which to predict any specific oil price over the next ten years. As discussed in Section 8, the critical uncertainty concerns the ability of the Persian Gulf states to restrict production so as to increase the price for their sales and the sales of other countries not taking part in output restriction. These political matters cannot be forecast with any degree of accuracy. As a result, the price could drift up or down over a period of years within a range of $4.00 to $12.00 per barrel, and it becomes impossible to evaluate Project Independence with precision. All that can be done here is to concentrate our analysis on the range of possible quantities and prices of oil and gas from abroad.

□ *Three: The Costs of Synthetic Fuels*. Sooner or later, liquefaction or gasification of coal will take place in the United States, and there will be substantial development of oil-shale resources. The issue is not whether such resources will be forthcoming, but when there will be capacity sufficient to provide substantial volumes of oil-equivalent supplies. The timing is not easy to estimate. Any assessment depends on the trade-off be-

tween the pace of development and its cost in terms of resources and environmental damage. This trade-off is not well-defined at present; while several liquefaction or gasification technologies are under active development, they involve untested technology. Where experience with particular processes has become available, operation has taken place at a scale from 10 to 30 per cent of the size of contemplated commercial units.

Estimates of the price incentives necessary to bring these new processes on-line, and at capacity levels supporting production of millions of barrels per day, can be made only within very wide ranges. Attempts are made in Section 7 to summarize data currently available on the processes and establish the ranges of likely costs for each. While they do not promise significant supplies by the early nineteen-eighties at prices comparable to those for fossil fuels, there may be some chance that these processes can make at least modest additions to domestic energy resources in this period.

☐ *Four: Expansion Capacity of the Construction Industry.* In the process of scaling up the domestic fuel industry, tremendous pressures will be placed on particular segments of the construction industry. Prices charged for construction might rise steeply as a result, and critical bottlenecks could develop in completing the schedule for achieving independence in the nineteen-eighties. These problems in construction may be exacerbated by problems in transportation of fuels—there may not be sufficient capacity to provide unit-train service for coal from the western regions of the country, for example. The expansion capabilities of the construction industry, the transportation industries, and providers of industrial inputs such as the water system of the United States are not well understood at the present time. Further careful consideration of the "scaling" effect on industries serving the energy sector of the economy is required.

☐ *Five: The Nature of Security.* Foreign sources of energy are highly diverse in the security problems they present. The level of American vulnerability is a complex function of the total import volume, the fraction of imports from any one country, and the specific sources of imports. As a result, there is critical uncertainty about the dimensions and the likelihood of the disruptive events that Project Independence is trying to guard against. This makes it difficult to evaluate Project Independence, since the nature of the security gain is not well specified.

Uncertainties in these five areas make it extremely difficult to analyze *any* policy favoring self-sufficiency in energy. But there can be no doubt that Project Independence will require much higher levels of domestic prices than are likely to occur without independence. This will be shown in the next section in summary form, and in the following sections in some detail.

Two: Energy Supply and Demand in 1980

When trade takes place with foreign suppliers, the price of energy can never rise above the price at which supply would equal demand if only domestic supplies were available, since importation from abroad must add some quantity to supply, and thus reduce the price. Therefore, we ask how high the price may be for exclusively domestic supply-demand equilibrium, since the answer to this question provides a first indication of the "cost" of security.

Tables 2.1 and 2.2 present a general picture of domestic energy market in 1980, with all quantities converted into equivalent barrels of oil.[1] Supplies of different fuels and overall energy demand are estimated at prices of \$7.00, \$9.00, and \$11.00 per barrel (in constant 1973 dollars), and the results define points on approximate supply and demand curves for total energy. By looking at the intersection of these curves—the point where domestic supply and demand appear to be in balance—we can predict the prices implied by a goal of self-sufficiency at the end of the decade.

Table 2.1 contains supply estimates based on detailed econometric studies of oil and natural gas. These analyses rely on extrapolation of the recent behavior of energy markets, and as such the forecasts for 1980 are likely to be an optimistic extension of patterns in the nineteen-sixties and early nineteen-seventies. The table also shows two estimates of demand, one econometric and one judgmental. The econometric estimate (Hudson-Jorgenson) is based upon a large-scale econometric model of energy demand in the United States, and reflects a relatively strong change in demand when prices change. The judgmental estimate, like the judgmental estimates for individual fuels from which it was compiled, does not take explicit account of the response of energy demand to price changes.

Table 2.2 shows the same two demand estimates, but

[1] A fuel is made "oil equivalent" by finding the number of barrels of oil which has the same heating value as a given quantity of that fuel.

Table 2.1: Energy Equilibrium in 1980, Using Supply Forecasts Based on Econometric Models. Such forecasts are extrapolations of conditions in the nineteen-sixties and early nineteen-seventies. Here they are compared with two forecasts of demand. Using the econometric demand forecast by Hudson and Jorgenson, the overall prediction is that domestic supplies might meet demand at a price as low as $9.00 per barrel. But using the judgmental demand forecast, the price is predicted to be near $11.00. A calculation by Martin Baughman, using the M.I.T. Model of Interfuel Substitution, shows a market-clearing price of $12.50 per barrel.

		Millions of barrels per day equivalent, at prices per barrel:		
Fuel	*Source of estimate*	*$7.00*	*$9.00*	*$11.00*
Crude oil	Erickson-Spann	8.4	10.4	12.4
Natural gas liquids	M.I.T. model	2.1	2.2	2.4
Natural gas	M.I.T. model	14.7	15.8	18.9
Coal	M.I.T. analysis	7.1	8.0	8.0
Uranium and hydroelectric	Equipment survey	6.2	6.2	6.2
New technology	M.I.T. analysis	0.0	0.0	0.1
Total supply		38.5	42.6	46.0
Forecasts of total demand	Hudson-Jorgenson	44.2	42.4	40.6
	Judgmental	45.6	45.8	45.8

Table 2.2: Energy Equilibrium in 1980, Using Judgmental Supply Forecasts. In this table, judgmental supply forecasts for oil and natural gas are substituted for the predictions of econometric models shown in Table 2.1 The result is a prediction that the price of self-sufficiency will be well over $11.00 per barrel—even with the Hudson-Jorgenson econometric forecasts, which imply a large reduction in demand when prices increase.

		Millions of barrels per day equivalent, at prices per barrel:		
Fuel	*Source of estimate*	*$7.00*	*$9.00*	*$11.00*
Crude oil and natural gas liquids	N.P C. (Case I)	13.6	13.6	13.6
(including Alaskan)		(2.0)	(2.0)	(2.0)
Natural gas	N.P.C. (Case II)	11.5	11.5	11.5
Coal	M I.T. analysis	7.1	8.0	8.0
Uranium and hydroelectric	Equipment survey	6.2	6.2	6.2
New technology	M.I.T. analysis	0.0	0.0	0.1
Total supply		38.4	39.3	39.4
Forecast of total demand	Hudson-Jorganson	44.2	42.4	40.8
	Judgmental	45.6	45.8	45.8

it provides a contrasting prediction of supply, based on judgmental forecasts for oil and natural gas instead of analytical model results. These judgmental forecasts were made by individuals or organizations versed in the energy industry; their "inputs" included not only formal or quantitative modeling of recent experience but qualitative analysis of the future as well. As a comparison of the tables shows, the econometric and judgmental forecasts of oil and gas imply similar levels of supply at the lower end of the price range, but the econometric models yield significantly higher supplies at high prices. Similarly, the two demand estimates are the same at approximately $5.50 per barrel (which is below the price range shown in the tables), but the econometric estimate falls below the judgmental one at prices above this level.

The tables indicate a wide range of possible values for the price required to clear domestic markets using only United States energy sources. At one extreme, the most optimistic forecast results from the econometric estimates of total supply and total demand in Table 2.1, which show market-clearing in the neighborhood of $9.00 per barrel. This is an extremely optimistic prediction: for it to occur, both the econometric estimates of supply (which are very probably optimistic) and the econometric model of demand (which shows a strong price response) must be assumed to hold. If the judgmental supply estimates of Table 2.2 prove to be more accurate, then even with demand that is highly price-elastic, the prohibition of imports implies a price near $13.00 per barrel. And if demand proved to be less responsive than estimated by econometric techniques, the price would be even higher.

All these forecasts are necessarily imprecise. The judgmental estimates normally imply conservative assumptions about price response, or they ignore price altogether—a clear weakness of the judgmental approach. On the other hand, the econometric models are limited in their capacity to consider the effects of future resource depletion or constraints on supplies of equipment and personnel. Hence the judgmental and econometric methods should be used to complement each other, so in this case the truth likely falls somewhere between the low clearing price yielded by econometric methods and the high price implicit in the judgmental analysis.

Until more experience is gained at these high price levels, the uncertainty over this range of prices will remain. On balance, however, the results point to the conclusion that the price of energy would be from $10.00 to $12.00 per barrel if supplies were limited to those within the United States.

The Supply Forecasts

The economic and judgmental forecasts of supply are described in detail in Sections 3 through 7. But here it may be appropriate to characterize them in general terms, so as to point out the extent of imprecision in the numbers shown in the tables.

□ *The Bases of the Forecasts.* The economic analyses in Table 2.1 show four important sources of domestic energy: crude oil, natural gas, coal, and nuclear and hydroelectric power. The crude oil sources are forecast to produce more from both onshore and offshore domestic wells in 1980 than at the present time, because the incentives of increased price more than compensate for depletion of inground reserves. The supplies of natural gas are also characterized by significant growth over the next few years, as a result of a doubling of field prices, which more than compensate for depletion effects there as well. In both oil and gas, it is assumed that significant new discoveries are made offshore in areas previously restricted from exploration, and that these resources are developed on a large scale. The supplies of coal are predicted with the assumption of an entirely new industry—strip-mining in southeastern Montana.

There are two critical estimates which must be made in forecasting energy supplies: supply responsiveness to price increases, and depletion effects. These estimates are quite imprecise, because of poor data in all energy industries—particularly in coal, where there is no industry at all in Montana at the present time.

It is more difficult to assess the judgmental forecasts reported in Table 2.2. Here, one usually cannot know what factors determined the estimate, nor can one consider the variation around the forecast. Thus these forecasts could be more subject to error than an economic forecast, but there is no way of knowing this. The approach here has been to use the forecasts that have been made in most detail, by individuals or organizations who have worked for some time on either the procedures for forecasting or the forecasts themselves.

□ *The Sources of the Forecasts.* The economic forecast for oil supply is based upon a crude-oil supply model in existence for more than a decade. It was first constructed by Franklin Fisher at M.I.T., then reconstructed and updated in more recent years by Edward Erickson and Robert Spann at North Carolina State University. The economic forecast for natural gas is based upon a large-scale econometric gas model at M.I.T. that has been used extensively for forecasting the results of policy change in the regulation of natural gas. The supplies of coal have heretofore been neglected by analysts; our procedure has been to use the expertise and judgment of two economic analysts working on coal at the present time—Martin Zimmerman of M.I.T. and Richard Gordon of Pennsylvania State University. They produce a combination economic-judgmental forecast that is used in Tables 2.1 and 2.2. Similarly, supplies from new technology are estimated by a group of engineering analysts versed in these technologies and working under the direction of Herman P. Meissner at M.I.T. Their forecasts are judgmental, but heavily bolstered by analytical work on the performance of new technology in the recent past. Finally, supplies of uranium and hydroelectric energy are fixed by present plant capacities and by the construction of new plants in the next few years. Therefore, forecasts of such supply are limited to what these plants can produce, stated in terms of net output.[2]

In Table 2.2, we substitute the National Petroleum Council judgmental forecasts for the econometric forecasts. The N.P.C. study is noted for exceptional detail and for having reconciled a wide variety of views of those in the oil industry concerning future supplies. It is not an analytical or even a formal forecast; there is some doubt whether the N.P.C. study even relates supplies of crude oil, gas, or coal to alternative prices. But it is used here because of the authority of those who participated in the N.P.C. exercise—the wide range of interests and expertise was extremely impressive—and because these individuals dealt directly with *future* depletion, while the econometric models only extrapolate past depletion.

The Hudson-Jorgenson Model of Demand

Edward Hudson and Dale Jorgenson attempt to forecast demands and supplies for nine broad industrial sectors over the period 1973 to 2000. They can then obtain a projection of total energy demand and supply over that period. Three basic models are used to provide the forecasts. First, a "long-term" macroeconomic model is used to predict levels of final G.N.P. demand and also to predict the prices of the factors of production—capital and labor. Then, taking these final demands and prices as given, two further models—a production model and a consumer-behavior model—are used to calculate the inter-industry flow of products and the prices for these products.

To calculate final energy demands, Hudson and Jorgenson must forecast total demand for products and the energy used per unit of product. In general, this computation involves a very complicated model, since both total demand for products and the demand for inputs used in creating these products are determined simultaneously as a function of equilibrium prices—the prices at which markets clear. Hudson and Jorgenson simplify this problem by separating the consumption and production sides of the model through assuming an input-output structure of production. However, as an advance over previous work, they estimate the input-output coefficients as a function of prices. Thus the procedure for determining energy demand begins with final demand for products by four sectors: private consumption, private investment, government expenditures, and net exports. Given final demand, the modellers multiply by energy input per unit of final demand, which is calculated from the input-output coefficients. Then, summing across all final demand, an estimate of total energy demand is determined. As prices change, the input-output coefficients will change, and thus energy use will respond to changes in price.[3]

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[2] On the whole, the supply response to price in the \$7.00 to \$11.00 range seems roughly in line with an elasticity in the neighborhood of 0.4 (that is, supply will rise .4 per cent for each one per cent increase in price). Of course, this does not mean that this approximate value of the supply elasticity holds outside the range.

[3] The elasticity of demand implied in these estimates is approximately −0.15 over the range of \$7.00 to \$11.00 per barrel,

Fuel	Residential and Commercial Sector	Industrial Sector	Transportation Sector	Electric Utilities	Total
Coal	150	6,500		10,200	16,850
Petroleum	6.800	6,000	22.000	2 520	37,320
Natural gas	10.500	12,000	1,000	6,000	29,500
Electricity (net)	6,000	3.600	20		
Nuclear				9,600	9,600
Hydroelectric				3.500	3,500
Total	23,450	28,100	23,020	31,820	96,800

Table 2.3: Judgmental Demand Forecasts for 1980, in trillion B.t.u. per year. The economy has been divided into the three primary sectors shown, and a fourth that produces electricity for the other three. The totals for nuclear and hydroelectric sources represent the total K.w.h. produced, expressed in terms of the B.t.u.s required to generate the same amounts from fossil plants. The total of 96,800 trillion B.t.u. per year, converted to oil-equivalent units, is the judgmental forecast of total 1980 demand which appears in Tables 2.1 and 2.2.

In Tables 2.1 and 2.2, we use the forecast of total energy consumption from the Hudson-Jorgenson model. The model shows strong price sensitivity to changes in demand, having been based on data from a period in which reduced prices were accompanied by increased consumption. These data are used for forecasting a period in which price *increases* are expected to be followed by *reduced* demands. It is therefore assumed that the demand processes observed in the past, and formalized by Hudson and Jorgenson, are reversible, although there may be some doubt about the completeness of the reversibility.

The Judgmental Demand Forecasts

Many attempts at forecasting demand have been based on projections of recent trends in energy consumption and on the forecasters' knowledge of individual industries. While such forecasts do not enable us to estimate demand responses to changes in prices, they may still be useful as "boundary" projections for the relatively near future. Such a forecast is used to predict total energy demand in Tables 2.1 and 2.2

In judgmental estimates, energy demand is normally broken down into three primary use sectors—residential and commercial; industrial; transportation—and one energy "transformation" sector—electricity—which transforms primary fuel into electrical energy, which is then an input into the three primary sectors. Demand in each of the primary sectors for a particular energy source (including electricity) is affected by fuel price and other economic and demographic variables.

☐ Demand in the *Residential and Commercial Sector* includes the following end-uses: lighting, air conditioning, television sets, refrigerators and small household appliances (these use electricity almost exclusively); cooking and dryers (using electricity and gas); and space and water heating (oil, gas, and electricity primarily). The total use of fossil fuels by this sector in 1970 was 14,000 trillion B.t.u. With 2,900 trillion B.t.u. of electricity (net), the total consumption was 16,900 trillion B.t.u.

☐ The use of energy by the *Industrial Sector* varies considerably among industries. Total energy consumption by this sector was about 23,300 trillion B.t.u. in 1970, of which 2,300 trillion (net) is attributable to electricity. Four industries account for about half of total industrial energy expenditures: primary metals for 21.5 per cent; petroleum and coal products for 15.4 per cent; food and kindred products for 8.5 per cent; and stone, clay, and glass for 8.3 per cent. Knowledge of substitution possibilities among fuels for these and other industries is quite limited.

☐ The *Transportation Sector* includes autos, buses, trains, subways, and so on. The primary energy source for this sector is gasoline, and there is little prospect for very much substitution among fuels in the short-run. As a result, anticipated gasoline supplies, at various prices, should be assigned to this sector first when making estimates of the future energy supply-demand balance. The total energy consumption by transportation was 10,800 trillion B.t.u. in 1970, of which only a trivial amount was electricity. Of the total, about 8,100 trillion B.t.u. was provided by gasoline.

☐ *Electricity demand* will be limited to the capacity available—either by prices or controls. Thus, we look first at supply. Electricity is produced from coal, oil, gas, uranium, and hydroelectric power. To generate the 1.56 million gigawatt-hours produced in 1970, fuels were consumed in the following proportions: nuclear, 1.4 per cent; hydroelectric, 16.2 per cent; coal, 46.4 per cent; oil, 11.6 per cent; gas, 24.3 per cent. (Note how little oil is used.) This translates into 322 million tons of coal, 325 million barrels of oil, and 3.89 trillion cubic feet of gas.

Projections of electricity supply for 1980 will probably be the most reliable of any energy forecasts. Given a five- to eight-year planning and construction horizon, most of the additional supply that will be available in 1980 is from generating plants either under construction or in advanced planning stages.

The projections in Table 2.3 are a combination of available predictions of demand in 1980, as adjusted by our own credibility weightings. They are based largely on studies by National Economic Research Associates (N.E.R.A.), Morrison and Readling, the National Petroleum Council (N.P.C.), and Chase Manhattan Bank.[4] The studies that we relied on most

oil equivalent. (That is, demand changes by 0.15 per cent when the price changes by one per cent, rising when the price falls, and falling when the price rises.) Naturally, this is at best a rough approximation, and it cannot be assumed that this elasticity holds for prices outside this range.

[4] The sources are the following: Chase Manhattan Bank, "Outlook for Energy in the United States to 1985," June, 1972; Warren E. Morrison and Charles Readling, "An Energy Model of the U.S. Featuring Energy Balances of the Years 1947-1965 and Projections and Forecasts to the Year 1980 and 2000," U.S. Bureau of Mines, 1968; National Economic Research Associates, "Fuels for the Electric Utility Industry 1971-1985," August, 1972; National Petroleum Council, *U.S. Energy Outlook: A Report of the Committee on U.S. Energy Outlook*, December, 1972.

heavily were those by N.E.R.A. and N.P.C., both because they made fairly detailed projections for 1980 and because they carefully spelled out the derivations of their figures.

We first examined the total consumption forecasts for each of the four broad consumption categories. The variance for residential and commercial consumption forecasts was quite small for all studies, with a range of about 22,500 to 25,000 trillion B.t.u., we picked a value close to the mean. Industrial consumption forecasts were all fairly close, except for N.E.R.A.'s, which was far above the others. We therefore omitted the N.E.R.A. figure and chose a value close to the highest of the remaining three (the range here was between 26,400 and 28,500 trillion B.t.u.) in order to give some weight to the N.E.R.A. projection. The forecasts for transportation ranged from 21,700 to 25,700 trillion B.t.u.; we took the mean. For electricity, the N.E.R.A. forecasts were adopted because they specialize in this area and seem to be most familiar with construction and power-generation trends in the industry.

Predicting the consumption of specific fuels by each of the four sectors was more difficult. We used N.E.R.A.'s estimates of electricity consumption by each sector. N.E.R.A. and N.P.C. had virtually identical estimates for B.t.u. conversion requirements based on fairly well-established engineering conversion coefficients, so the N.E.R.A. data were used here as well. The N.E.R.A. data were utilized to allocate total B.t.u. requirements for electricity generation among fuels, because it seems that they had the best access to available data and appear to have analyzed it carefully.

Allocating our predicted 1980 demand among fuels in the transportation sector was no problem, since this sector consumes petroleum almost exclusively.

The residential and commercial sector uses only a slight amount of coal, and its proportion of total residential consumption has been declining. We projected a continuing linear decline to 1980, and, after subtracting electricity consumption, allocated the remaining B.t.u.s between petroleum and natural gas on the basis of recent usage figures.

For the industrial sector, there was little to go on, since neither N.P.C. nor N.E.R.A. made the relevant projections for each fuel. We therefore took the 1970 proportions by fuel and applied them to the industrial demand left after subtracting electricity demand.

The resulting total energy demand is 96,800 trillion B.t.u. in 1980, as shown in Table 2.3. Converted to oil-equivalent units, this is the demand for 45.6 million barrels per day that appears in Tables 2.1 and 2.2.

Demand Reduction by "Conservation"

The demand estimates in Tables 2.1 and 2.2, made using the Hudson-Jorgenson model, showed a reduction of 1980 demand from 44.2 million barrels per day at $7.00 per barrel to 40.6 million barrels per day at $11.00. This change is presumably the result of substitutions for energy, conservation of energy in consumption, and increased energy productivity in production of goods and services. An alternative way to estimate the potential for reductions in demand is to determine where new or existing technology can bring about reductions in energy consumption without degradation in function performed. When supplemented by appraisals of conservation efforts (based on experience in the last six months), these estimates can serve as an indication of the potential for demand reduction induced by government policy and higher prices.

In the industrial sector, a rough survey of the responses to increasing fuel prices and fuel shortages shows that a 15 to 25 per cent reduction in energy consumption can be obtained by eliminating heat leaks and improving waste-heat recovery. It is hard to know how many such changes, recently made, were caused by the threat of shortage and by public relations campaigns, as compared to rising prices. Thus we cannot know if further reductions might result from high fuel prices alone, or whether they would require special incentives (such as fast tax write-offs) or various forms of controls. Without attempting to specify the relative influences of price and other incentives, we will take the 15 to 25 per cent potential savings in the industrial sector as a "once-and-for-all" demand reduction in industrial fuels between now and 1980.

Transportation fuel demand is predominantly determined by consumer attitudes, and therefore has a high component of uncertainty. Rather than attempting to predict changes in consumer tastes, we have considered a relatively simple set of feasible technological adjustments; they could be accomplished by modification of new cars and some retrofit of old cars. Electronic ignitions on all new cars and part of the existing stock could save by 1980 an amount of fuel equal to five to ten per cent of the consumption by all cars and a large proportion of trucks. This would come to an estimated 60 to 120 million barrels of gasoline in 1980. Radial tires on all new cars, plus replacements on old cars, would result in a five to ten per cent savings, yielding 45 to 90 million barrels of gasoline in 1980. Policies to discourage automatic transmissions and air conditioning, leading to a 50 per cent reduction of these items during the next six years, would yield a 95 million barrel savings of gasoline. The total savings in gasoline from these changes would be from 200 to 305 million barrels in 1980.

Potential reductions in consumption in the residential-commercial sector have been estimated on the basis of possible improvements in the existing stock of buildings. Items considered included storm windows and doors, six-inch ceiling insulation, sealing and weather stripping, solar assist and energy storage in heating, heat pumps, heat exchangers, and increased burner efficiencies. These improvements were considered by fuel and by region of the country.

The measures we have discussed do not require a change in life style or drastic limitations on the use of energy. The experience of the last six months in New England indicates that a savings as great as 15 per cent in heating oil is attainable by thermostat (and attitude) adjustments which do not change living conditions significantly. A similar adjustment has occurred in the consumption of electricity—in the short run, at least. The transportation sector was less responsive initially, but a combination of price increases and shortages has produced ten to 15 per cent short-term reductions.

These results make it reasonable to expect that a continuing and forceful campaign of public information could significantly influence energy-use patterns in the transportation, residential, and commercial sectors. Without direct controls, consumption could probably be reduced by ten per cent of 1971 consumption. Sum-

ming over all the estimates we have made, it is possible to show savings in a range from 4 to 8 million barrels per day by 1980.

This gross estimate may be compared with the demand estimate of 51.1 million barrels per day prepared by the Chase Manhattan Bank. The Chase forecast was made before problems of insecurity of supplies and rising price were evident, so notions of energy conservation were not considered. Correcting the Chase forecast by our estimate of savings yields a demand of about 43 to 47 million barrels per day, which brackets the judgmental forecast reported earlier in this section.

1980 and Beyond

The rough dimensions of energy supplies and demands in 1980 show that complete independence from imports of energy will probably cause prices of $10.00 to $12.00 per barrel, or more. Beyond 1980, however, the picture could change. We have not examined conditions in later years in sufficient detail to determine how supplies and demands might balance, for our purpose here is to evaluate the goal of self-sufficiency by 1980. It may be interesting, nonetheless, to briefly speculate about the possibilities for independence in 1985.

Our speculation is that in 1985 self-sufficiency can be achieved only at price levels (in 1973 prices) very similar to those shown in Tables 2.1 and 2.2 for 1980. For market-clearing prices to be lower than $10.00 to $12.00 per barrel, additions to domestic production would have to exceed additions to demands from population increase, economy-wide income increases, and other factors. According to the Hudson-Jorgenson model simulations, demand growth will be approximately 2.8 per cent per year at prices in the range of $9.00 to $10.50 per barrel. At this growth rate, about 1.2 million barrels per day are added to demand each year—a total of 6 million barrels per day over the period 1980 to 1985.

Thus new supplies from new sources over this five-year period would have to exceed 6 million barrels per day—and exceed this figure by enough to compensate for depletion of domestic oil and gas, *and* bring prices down. Given the magnitude of the construction required to bring on new technologies at that supply level, and the consequent effects on costs of fuel production from these new technologies, such huge additions to supply are not likely to be forthcoming. A hopeful—if not over-optimistic—forecast is that additions to supply, working against inexorable demand increases, would be sufficient to maintain prices in the neighborhood of $9.00 to $10.00 per barrel under a program to achieve autarchy in 1985. Once again, though, there is great uncertainty inherent in such a prediction.

Three: The Supply of Domestic Petroleum

The production of crude oil in 1973 was 9.2 million barrels per day. The total consumption was about 17.0 million barrels per day, which included about 6.1 million barrels per day of imports, and 1.7 million barrels per day of natural gas liquids. To raise production to higher levels by 1980 would require prodigious exploration and development, as an appraisal of present conditions and forecasts shows.

The National Petroleum Council's projection for 1980 expects Alaskan North Slope production to be from 2.0 to 2.8 million barrels per day, although 2.0 million barrels is likely to be closer to the truth due to delays in pipeline construction. Continental U.S. offshore production is expected to range between 1.6 and 2.7 million barrels per day. Total production of petroleum liquids is projected to be from 8.9 to 13.6 million barrels per day, depending on a number of political and economic factors. Thus the most hopeful N.P.C. projection—13.6 million barrels per day in 1980—could require up to 8.9 million barrels produced onshore (in the lower 48 states) as compared to 7.8 million in 1972 and 7.6 million in 1973.[1]

In 1973, onshore production was 12.0 per cent of onshore reserves. Assuming that this ratio can be maintained, and that there will be a smooth buildup to a 1980 production of 8.9 million barrels daily, 21.1 billion barrels will be consumed in seven years, and 27.1 billion barrels of reserves will be needed to support production in 1980. The total is 48.2 billion barrels; subtracting the current reserves of 22.8 billion barrels leaves 25.4 billion to be added in seven years, or 3.6 billion per year. This total has been equalled or surpassed three times since World War II, and is technically feasible, but it must now be done under much less favorable conditions than before.

It is generally agreed that discovery of new fields has been dwindling for a long time. In 1946-1949, gross new reserves developed were 11.9 billion barrels. But

[1] In preparing these estimates, and others below, we have attempted to reconcile differences between detailed figures provided in the initial task group report of the Oil Subcommittee of the N.P.C. study, and the ultimate summary report, *U.S. Energy Outlook*, December, 1972.

9.1 billion was provided from fields newly discovered during those years; hence discoveries made up for three-fourths of new reserves developed. This fraction dwindled steadily, and in 1965-1967, while 7.6 billion barrels of new reserves were developed, only 2.0 billion were added from newly-discovered fields. (The percentage was even lower in later years, but data on recent-year discoveries are inherently incomplete, and should not be used.) In other words, the industry has to an increasing extent created new reserves in old fields, both by finding new oil in extensions and new pools, and by improving recovery. This process should continue, but it is unreasonable to expect it to continue at the average of past costs. That is, the less our underground stock is replenished by *new* fields, the harder we must work the *old* fields. Thus the costs of developing new reserves and productive capacity will rise.

An indication of considerably increasing costs is provided by reserves added by the completion of an oil well. The average increased from a low of 80,000 barrels in 1957 to a peak of 218,000 in 1970, then fluctuated between 142,000 and 212,000. This development is ominous because of the decline in drilling and in new reserves. During 1955-1970, the number of wells drilled fell from 34,000 to 14,000 per year, but the amount of new reserves established declined only mildly. Because of better regulation, fewer useless wells were drilled, and higher capacity, lower-cost wells took a disproportionate share of the increase in demand in the late nineteen-sixties. Thus the rise in development costs due to a constantly less favorable resource base was offset by a once-for-all regulatory improvement and the resulting concentration on better prospects. Since the number of new oil wells decreased from 12,800 per year in 1970-1971 to 10,600 in 1972-1973, oil operators must have continued to drill even more selectively. For reserves added per well to shrink during such a time shows a rapid rise in the real cost of developing new reserves from old fields. If so, the past average of the cost required to develop reserves must be a serious under-estimate of future costs needed to develop new reserves. As drilling again expands, the reserves added per unit of drilling must be expected to fall again.[2]

The Judgmental Forecast

Against this background, we consider the National Petroleum Council estimates for 1980. These are based on historical experience; they assume that what has been found and developed is a reasonably good sample of what will be found and developed. The N.P.C. estimates embody the judgments of the best informed people in the industry, and at a disaggregated level, so that the judgments are relatively independent of each other. Also tending to make them plausible is the fact that unrecovered oil-in-place in the lower 48 states is about ten times proved reserves, which indicates that there is a big stock of oil which was uneconomical to recover at previous prices.[3]

The problem is that the N.P.C. projections do not follow from a model, but are based almost entirely on perceived trends. The four principal supply cases that the N.P.C. investigated were:

☐ *Case I*. Expansive supply, requiring a vigorous effort fostered by early resolution of environmental controversies, ready availability of government land for energy resource development, adequate economic incentives, and a higher degree of success in locating currently undiscovered resources than in the recent past.

☐ *Case II*. Less expansive supply, assuming improvement in finding rates for oil and gas, and a quicker solution to problems in fabricating and installing nuclear power plants than in the recent past.

☐ *Case III*. Less expansive supply, assuming a slightly different but equally cautious mix of policy changes. The forecasts are much the same as those of Case II.

☐ *Case IV*. Low supply, representing the likely outcome if environmental disputes continue to constrain the growth in output of all fuels, if government policies prove to be inhibiting, and if oil and gas exploratory success does not improve over recent results.

None of these cases incorporates price as a determinant of exploration or development. In the N.P.C. analysis, "price" is the *result* of a given rate of drilling and finding. The N.P.C. procedure is to assume alternatively a high, medium, or low drilling rate and a high or low "finding" or reserve-addition rate. From these are created the four cases: high drilling and finding rates in Case I; a medium drilling rate but a high finding rate in Case II; a medium drilling rate but a low finding rate in Case III; and low drilling and finding rates in Case IV. The apparent anomaly that Case II shows less produced at a lower price, while Case III shows less at a higher price, is thus not a mistake but follows from the assumptions. In each case, the N.P.C. has used averages of drilling and finding, but without trying to relate the two. Estimating the amount of capital spending needed to maintain a high drilling rate, for example, they take a 15 per cent rate of return, and divide the required return in dollars by estimated production under a high finding rate, deriving a "price" of \$5.64 per barrel (adjusted to the 1973 price level).

There are two reasons why this "price" which *results*

[2] With depletion rates around 12 per cent or more, costs would rise very rapidly if operators attempted to drain pools more rapidly. It can be shown that the average capital cost of any project is approximately equal to $(I/Q)(a + r)/365$, where I/Q is the investment needed per additional daily barrel, a is the decline rate, and r is the discount rate or cost of capital. That is, a price just equal to this amount would barely compensate for the investment. Increasing the rate of depletion would, of course, be less attractive the greater the rate of depletion already is, since it would require larger investment. It also can be shown that the speed-up cost is equal to the development cost multiplied by a factor $(a + r)/r$. Where a and r are approximately equal, as they are today, with both the rate of decline and rate of discount near or above 12 per cent, the marginal speed-up cost is twice the incremental capital cost. For example, if it cost \$5,000 to develop an additional daily barrel, and a and r both equalled 12 per cent, the annual capital cost would be about \$3.44 per barrel. But to speed up depletion of a given reserve would cost about \$6.88 because, in effect, of the feedback on the existing operation. Hence the price would have to double before the previously break-even operation was worth expanding.

[3] Alaska deserves special mention. A very small amount of exploratory effort at the North Slope has yielded one gigantic find. Costs are very low by comparison with current world prices, and the discovery of a few more Prudhoe-Bay-type reservoirs would change the national picture drastically.

from drilling and finding may seriously underestimate the price needed to *create* incentives for Case I supply. First, the N.P.C. does not discuss the likely rate of expenditure for finding. The most likely combination is of a very low finding (reserve addition) rate with a very high drilling rate. Onshore reserves added in 1971-1973 averaged less than 1.8 billion barrels per year, while drilling and real development expenditures did not decline correspondingly. If we are to double this performance, up to about 3.6 billion barrels per year, we can hardly expect to escape with less than three times recent outlays. Hence the N.P.C. 1980 "price," which is only 54 per cent higher in constant dollars than the 1970 price, cannot possibly be an accurate assessment of the necessary 1980 expenditures per unit of new reserves and capacity installed.

Furthermore, the N.P.C. does not touch on the wide dispersion of onshore cost. If a given "price" is just enough to cover capital and operating cost of all new oil developments, this average will be greater than the costs of the lowest-cost capacity, but less than the highest. Only if the industry were to subsidize the production of high-cost oil out of the profits of low-cost oil could this "price" be treated as the price needed to bring in the high-cost oil. The range of cost is unknown, but must be very large.

Given these two problems with the N.P.C. estimates—the most recent costs per barrel of new reserves added, and the need to cover high-cost sources—we can at least be certain that the price needed to bring in 13 million barrels per day in 1980, or possibly much more, must be far higher than the $5.64 estimated by the N.P.C. We might suppose that to double the 1972-73 performance would require tripling the price, hence the $4.30 for old oil would increase three-fold to $12.90 in 1973 dollars. It seems unreasonable to assume a price below $9 if, with no imports, higher coal and gas production keep oil production to no more than 13 million barrels per day.

The forecasts shown for the N.P.C. in Table 2.2 are a combination of Case I estimates and our judgment of the appropriate price for Case I. Under almost ideal conditions, the Case I production for the lower 48 states would be forthcoming at $7.00 per barrel (which is above the N.P.C.'s $5.64 but is not inconsistent with their report, since $5.64 is not the "supply price" equal to marginal costs). The Case I production is certainly consistent with $9 and $11 prices; since no additional supply is shown in the N.P.C. study to be forthcoming at these high prices, we do not assume any more supplies than at the lower price.[4]

The Econometric Forecast

The economic model forecasts of supply are derived from the Erickson-Spann econometric model (as described in M. F. Searl, *Energy Modeling*, Resources for the Future, March 1973). This has much to commend it, since it models a company's search for profits as a problem of decision-making under uncertainty, with oil and gas as joint products (they are often discovered together). In the model, oil and gas discoveries are functions of the prices of oil and gas, interest rates, Texas shutdown days, and a time trend. The equations imply little cross-effect on the discoveries of oil from the price of gas, but substantial effects on production of oil from the price of oil—an 8.7 per cent production increase results from a 10 per cent price increase—and negative effects from depletion, which the model places at 4.33 per cent per year.

The Erickson-Spann oil supply model makes no explicit distinction between onshore and offshore drilling activity in the lower 48 states. This is a defect for the purposes at hand. Because expanded domestic oil supply will depend critically upon substantially increased offshore activity, and because offshore activity in turn depends upon government policy on the rate of leasing, the areas leased, and environmental protection policies, it would be convenient if the Erickson-Spann model were disaggregated into onshore and offshore sectors.

Another difficulty is that over the post-World War II period the real price of oil did not change drastically. This creates two problems. One is that of using the model's "supply elasticity coefficient" of .87 (the percentage that supply changes for each one per cent change in price) to forecast a supply response that is outside the range of the price data from which it was estimated (the prospective level of real crude oil prices implicit in Project Independence are about double to triple those which prevailed in recent years). The other problem is whether the function is reversible. In the past, prices declined and supply declined so that equations fitted to the data showed a positive supply relationship. In the future, prices are expected to increase so that—if the equations can be used to infer movement in both directions—supply should increase. This is problematical.

Still, all these problems considered, the Erickson-Spann estimates of oil supply response are the only systematic estimates which explicitly model the long-run response of oil production to economic incentives in an analytically tractable way.

The forecasts from the Erickson-Spann equations are heavily dependent on the supply elasticity and depletion coefficients. Of the two, there is greater justification for using the fitted price elasticity of .87, though the results should be viewed with caution when prices increase beyond the range of previous observations. But use of the 4.33 per cent depletion trend is suspect; this is a very low estimate of the yearly rate of depletion, so low as to be out of the range of recent figures, which run close to 13 per cent, but are counteracted by roughly a five per cent annual productivity increase. Rather than assuming 4.33 per cent, therefore, we assume a low but still technically feasable rate, 8.33 per cent, in keeping with new production of 2 million barrels per day from Alaska and additional production from offshore continental U.S. The supply forecasts that result are shown in Table 2.1.

[4] The exception is Alaskan oil, which is shown on a separate line in Table 2.2. While the table shows 2 million barrels per day from Alaska at all prices, this amount must be more secure at $11.00 per barrel than at $7.00.

Four: The Supply of Natural Gas

The shortage of natural gas in the United States has grown rapidly in the last two or three years. By now, it probably exceeds ten per cent of total demands. This is not a result of a shifting of demands to natural gas due to the Arab oil embargo. Rather, it is a continuous and systematic long-term shortage, and there is every reason to believe that it will not be eased appreciably in the remaining years of this decade under the prevailing Federal Power Commission price controls—even if the F.P.C. were to continue its recent policies of raising the price an average of three or four cents per thousand cubic feet on *new* contracts each year. If great pressure is put upon gas demands as a result of oil price increases beyond $6.00 per barrel, excess demand is likely to expand to more than a quarter of total demand in the next few years.

Because of the control mechanism operated by the F.P.C., production of gas could either increase or decrease greatly in the next few years. In order to provide a basis for analysis of public policies in gas, we will attempt to forecast supply with the M.I.T. econometric gas model,[1] assuming two quite different policies regarding gas prices. Both are alternatives to the *status quo*.

Supply Under Price Controls

The first alternative is to direct policies toward a price freeze. This is likely to occur under restrictive regulation such as that implied by Senate Commerce Committee Bill S-2506 (the "Stevenson Bill"), which calls for an expansion of regulatory jurisdiction for the Federal Power Commission to cover all sales at the wellhead (including intra-state sales). The bill requires that price ceilings be based upon historical average costs, so that this legislation seeks to stop the price increases now occurring under more "relaxed" F.P.C. regulation. The price implication might well be to limit increases to approximately one cent per year when these increases are justified by changes in average costs of drilling and production. There are many possible variations on this interpretation, but it is unlikely that price increases much greater than one cent per year are implied by the bill, since price increases of three cents a year are now being put into effect by the F.P.C., and the bill specifically delineates standards which would not allow such increases. The general thrust of this and similar legislation is to hold the line on present prices, so as to prevent gas sales from following the "pricing spiral" now seen in petroleum sales.

Holding the price line implies that there will be little additional incentive to explore and develop new reserves, or to restrict demands for natural gas as the price of fuel oil increases. Under this policy, new-contract field prices are assumed to rise, on average, at a rate of one cent per year, from roughly 34 cents in 1973 to 41.5 cents in 1980. As a result, wholesale prices throughout the United States are expected to rise on average to 49.6 cents by 1980. Assuming that wholesale prices rise 3.5 per cent per year, and population increases at one per cent per year, the market for natural gas is expected to grow. Moreover, conditions in oil markets have strong implications for excess demand in natural gas markets. Rising oil prices lead to substantial increases in demands for natural gas which cannot be satisfied at the regulated or frozen level of prices.

The effects of strong price controls are shown in Table 4.1. The low levels of annual production and high levels of demands result in significant excess demands—2 trillion cubic feet at the present time, increasing to 10 trillion cubic feet in 1980, or approximately 25 per cent of total 1980 demands. This shortage would be so great as to make it impossible for the pipelines to supply all the needs of established consumers. Permanent rationing would undoubtedly be put into effect. Most of its impact would be felt in the upper Midwest, where population and industrial growth are large and where the pipelines serving the region come from producing areas that are most depleted.

Supply Under Price Decontrol

The second alternative to present policy is the elimination of current restrictions on field prices. The purpose would be to provide incentives for increasing reserves and production (by higher prices) and for eliminating low-value uses of natural gas (by reducing demands through price increases). The use of market forces to add to supplies and reduce demands would have different effects, depending on how rapidly and extensively prices increased. Immediate and complete elimination of price controls would establish short-term equilibrium prices much greater than those that would persist over the long-run—particularly if there are short-term shortages in alternative fuels such as fuel oil.

[1] This model and its application to policy analysis is described in P. W. MacAvoy and R. S. Pindyck, "Alternative Regulatory Policies for Dealing with the Natural Gas Shortage," *Bell Journal of Economics and Management Science*, Vol. 4, No. 2, Autumn 1973.

Phased decontrol, however, could be put into effect in a way that would gradually ease restrictions on prices, so as to move them over a five-year period into long-run equilibrium.

Thus this policy does not require immediate deregulation—new-contract price increases could be limited by the Federal Energy Agency for some years, presumably to keep the increases in line with general cost-of-living increases. This implies a ceiling on new contract prices of approximately 50 cents in 1974 (the average price was 35¢ in 1973). There would be a three-cent price increase each year thereafter. Field price increases would feed through as price increases charged by pipelines to wholesale buyers, so that the immediate impact would be a two cent increase in wholesale gas prices across the country. By 1980, field prices on new contracts would rise to more than 73¢, while wholesale prices on all contracts would average 64¢.[2]

The price increases would substantially increase additions to reserves over a five-year period, and they would increase production, both because of the reserve additions and because of more intensive depletion of existing reserves. As shown in Table 4.2, production is expected to rise from 26 trillion to 33 trillion cubic feet over the period 1974-1980. At the same time, demands would diminish as consumers attempt to avoid the price increases. Excess demand is 1.7 trillion cubic feet per year in 1974, remains at 1.7 trillion cubic feet in 1975, but then declines to zero by 1980. In effect, the use of market forces should eliminate excess demand through a combination of additional supplies, reductions in use by buyers faced with higher fuel costs, and substitutions for this higher priced fuel.

The M.I.T. model simulations therefore support the position that phased price increases (leading to a reliance on market forces over the long-run) can be used to ameliorate the present and growing shortage of natural gas. As price incentives improve the profitability of additional drilling in the United States, more reserves are likely to be accumulated, and more production can then take place. Most geological estimates indicate that these reserves are available, albeit at higher costs of discovery and extraction. Higher prices to consumers will be more representative of the true value of this scarce resource, and consumer demand should respond accordingly.

Supply Forecasts in Tables 2.1 and 2.2

The supplies of gas likely to be forthcoming at different levels of oil prices can be estimated as follows: First, it is assumed that gas prices will be regulated for the rest of the decade, either according to "strong price controls" as in Table 4.1, or in the process of "phased deregulation" of prices, as in Table 4.2. Either way, markets will not be allowed to operate so as to eliminate differences between gas and crude oil prices. Second, it is assumed that crude oil prices of $7.00, $9.00, and $11.00 per barrel enter gas markets as an "outside" variable on the demand side—that is, higher oil prices add to gas demand—and on the supply side—higher oil prices add to discovery and production of gas, which is often found with oil. Inserting into the M.I.T. model the gas prices in Tables 4.1 and 4.2, oil prices of $7.00, $9.00, and $11.00 result in the supply forecasts shown in Table 4.3.

Year	Field prices on new contracts (cents per thousand cubic feet)	Additions to reserves (trillion cubic feet)	Production supply (trillion cubic feet)	Production demand (trillion cubic feet)
1972	30.1	9.8	19.4	23.4
1973	33.9	12.6	23.1	24.8
1974	35.0	14.4	23.7	26.6
1975	36.1	17.7	24.6	28.6
1976	37.2	20.8	25.6	30.7
1977	38.3	22.9	26.7	32.9
1978	39.4	24.7	27.8	35.1
1979	40.5	26.7	29.0	37.4
1980	41.6	28.9	30.3	40.0

Table 4.1: Natural Gas Supply Under a Regime of Strict Price Controls. Demands for gas increase, but there is little incentive for suppliers to meet them when the price is constrained. The result, in this forecast of the M.I.T. Econometric Gas Model, is a massive shortage—by 1980, one quarter of total demands cannot be supplied.

Year	Field prices on new contracts (cents per thousand cubic feet)	Additions to reserves (trillion cubic feet)	Production supply (trillion cubic feet)	Production demand (trillion cubic feet)
1972	30.1	8.3	19.4	24.4
1973	33.9	12.0	23.1	26.0
1974	49.1	14.8	25.7	27.4
1975	53.2	18.2	27.1	28.8
1976	57.3	22.9	28.5	29.9
1977	61.4	27.4	30.1	30.9
1978	65.4	31.0	31.6	31.6
1979	69.5	39.6	33.2	32.3
1980	73.6	38.4	33.0	33.0

Table 4.2: Natural Gas Supply Under Phased Price Decontrol. This forecast of the M.I.T. Econometric Gas Model assumes that prices are gradually decontrolled so that they double at the wholesale level by 1980. The higher prices curtail demand and provide incentives for producers to increase supply, and natural gas markets clear by 1978.

The table shows that gas markets clear by 1980 under phased decontrol over the entire range of oil prices, since higher oil prices add only slightly more to gas demand than they do to gas supply. For the same reason, gas price controls similar to "strict regulation" are not much worse under high oil prices than under low oil prices, although the size of the shortage exceeds 10 trillion cubic feet as early as 1978 if oil prices are pushed to $11.00 per barrel in 1975.

The estimates for 1980 given in Table 4.3 have been inserted in Table 2.1 (in millions of barrels per day). The imposition of some form of strict regulation is taken to be the most likely continuation of policy over the decade, even if Congress does not pass the Stevenson Bill. After all, this has been the most systematic long-

[2]Currently, contracts for *intra*-state gas are reportedly selling for as much as 75¢ to $1.00 per thousand cubic feet. This appears to imply a free-market price higher than we forecast. Actually, there need be no conflict here, for there is great excess demand in intra-state markets (some is demand diverted from other states) which is impinging on a narrow market for new gas. With phased deregulation of prices, this pressure would be relieved.

Table 4.3: The Supply (in trillion cubic feet) **of Natural Gas at Various Prices per Barrel of Oil.** On the left, strict price controls are assumed, and numbers in boldface type indicate excess demand greater than 10 trillion cubic feet. A shortage of that magnitude occurs by 1978 if the price of oil is $11.00, and by 1980 for all three prices of oil. On the right, phased price decontrol is assumed. Here, numbers in boldface type indicate excess demand less than 1 trillion cubic feet. This approximate equilibrium of supply and demand occurs by 1980 for all three prices of oil.

Year	Gas supply under strict price controls, with crude oil at:			Gas supply under phased price decontrols, with crude oil at:		
	$7.00	$9.00	$11.00	$7.00	$9.00	$11.00
1976	25.6	26.1	26.7	28.5	29.2	29.8
1977	26.7	27.7	28.7	30.1	31.2	32.4
1978	27.8	29.3	30.7	31.6	33.3	34.9
1979	29.0	30.9	32.7	33.2	35.4	37.5
1980	30.3	32.6	34.7	35.0	37.7	40.0

term policy of the F.P.C. (even if present Commissioners are departing from it). Thus the forecasts on the left of Table 4.3 are used in Table 2.1.

Much the same approach has been used in selecting the National Petroleum Council forecasts for gas liquids and for natural gas shown in Table 2.2. Here the Case II forecasts are shown, rather than the Case I as in crude oil, because gas price controls are likely to exert a significant influence over the next few years. Even with partial decontrol, the time lags in exploration prevent additions to supply before 1980 which are much more expansive than those of Case II.

Five: The Supply of Coal

The United States has vast reserves of coal, both in the well-explored regions east of the Mississippi River and in partially-explored portions of Wyoming and Montana. Whether these reserves can be developed in time to make a significant contribution to Project Independence depends upon the cost of mining and transporting the coal to final markets and on the growth in demand for coal. These factors, in turn, are influenced by political matters—principally environmental protection regulations against sulfur emissions from coal burned to generate electricity.

The potential pattern of development calls for operating on the *intensive* margin in the Eastern coal regions: exploiting existing underground mines more intensively, first for sulfur-free coal, and later for sulfurous coal. Before that sulfurous coal is considered, however, above-ground strip mining of new resources in Wyoming and Montana should come into operation on the *extensive* margin, thereby helping avoid violation of environmental standards. Thus the potential supply of coal at various prices consists of Eastern low-sulfur sources at now prevailing prices, Western strip-mined coal at prevailing or slightly higher prices, and Eastern high-sulfur coal at much higher prices—where the higher prices include the implied social costs of environmental degradation, or, alternatively, the costs incurred for stack-gas scrubbers or other purification devices.

There is a great deal of high-sulfur coal available at these higher prices, but the ability of the economy to utilize it is limited. This is because only so much coal can be used for energy—coal cannot be burned in automobiles or airplanes—and in the next seven to ten years the capacity of facilities able to burn coal is relatively fixed.

In an attempt to quantify this state of affairs, we begin with estimates of the unit cost of coal at present levels of production in the East, and at now-contemplated levels of production from the Western strip-mined regions. We will then ask whether costs of extraction would be significantly greater at higher rates of production, and thus begin to trace out a rough supply function for higher prices. At that point, the supply function will be "truncated" by introducing demand constraints.

The Cost of Eastern Low-Sulfur Coal

Because of the severe environmental damage caused by the technique in the hilly terrain of Appalachia, it is likely that strip mining will be limited there. In the flatter sections of Illinois and Indiana, there is evidence that large blocks of strippable coal are scarce. There-

fore any substantial expansion of coal production in the East will have to rely on underground mining.

The unit costs of coal extraction in the East are a composite of capital costs, labor costs, and developments in labor productivity. Concentrating on the low-sulfur coal, capital costs appear to be close to $2.50 per ton, a figure based on recent information for capital expenditures and a 15 per cent rate of discount over a twenty-year period.[1] Supplies, power, and other minor inputs, according to Bureau of Mines engineering estimates, add about $2.00 per ton.

Labor costs depend upon assumptions about wage increases and productivity changes. The projection of wages is a difficult problem. Wages are determined through collective bargaining and there is no unique wage for each level of employment and output. Therefore, at current levels of output a wide range of wages is possible. To any estimate must be added about an 80¢ per ton contribution to the Union Welfare Fund. R. L. Gordon estimates that in 1973 the average daily wage, including fringe benefits, was $65.60.[2]

This wage is not likely to remain constant, even at constant levels of employment. It is becoming increasingly difficult to attract new workers into coal mining. Moreover, the entry of inexperienced workers necessitates training costs not incurred when mining companies were able to draw upon an experienced labor pool. For these reasons labor costs will rise, although it is impossible to say how high. An extrapolation of the 1969-1973 rate of real wage increase yields a $97.00 daily wage in 1980. Allowing for a truly extraordinary increase, we take $150 as an upper limit by the end of the decade.

Labor productivity has not been increasing, and it is tempting to assume constant or declining productivity to 1980. This might be unduly pessimistic. The industry is beset by problems that, hopefully, are transitional. The Health and Safety Act of 1969 introduced many changes in mining procedures that are still having an effect; but if these are adjusted to, productivity should return to its 1969 level by 1980. We take as a 1969 productivity level that of a large new underground mine producing about 20 tons per man-day. Together with a daily wage of $150, this yields total 1980 costs of 53¢ per million B.t.u. A more optimistic prodictivity figure of 25 tons per man-day yields a cost of 47¢ for the same quantity.

These estimates lead to a point estimate of "supply." The 1980 total of capital, materials, and labor costs is roughly $3.80 to $4.20 per barrel, oil equivalent, delivered in Detroit. It seems reasonable to assume that the supply of Eastern low-sulfur coal (less than one per cent sulfur) will remain near its present level of approximately 200 million tons per year at this price. At higher prices, additional supplies should be forthcoming. For example, we assume that at $7.00 per barrel, the production of low-sulfur Eastern mines might increase to 250 million tons by 1980. Either estimate is a cautious extrapolation of present conditions.[3]

The Cost of Western Coal

Recent engineering studies of the Bureau of Mines establish the cost of mining coal in the Powder River Basin of northeastern Wyoming and southeastern Montana.[4] The region is a large new source of coal. Costs there are approximately $2.25 per ton exclusive of royalties and state taxes, and assuming discount rates of 15 per cent per year. (We exclude royalties since these are the returns that owners of low-cost or non-marginal reserves would earn. States taxes have been excluded because, while they vary from state to state, at present they are negligible on the whole.)

These costs are low. Assuming 17 million B.t.u. per ton, the Bureau of Mines figures yield a cost of about 13.2¢ per million B.t.u.[5] But these estimates may not include further social costs. The Bureau of Mines used the 1969 costs of land reclamation in their estimates, yet standards in many states have become stricter since then and are likely to become even more exacting. The costs depend on the amount of overburden that must be removed per ton of coal uncovered and on the topographical and climatic conditions of the area. Assuming reclamation costs of $5,000 per acre and a coal seam thickness of ten feet, then costs of reclamation are 28¢ per ton or 1.6¢ per million B.t.u. at the most.[6] This meets the environmental protection requirements at the present time; but this may not be enough to restore mined land to its former usefulness in agriculture. No one knows what the cost of complete restoration would be.

These estimates of costs reflect present conditions. Three factors could change future costs: depletion of

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[1] In February, 1973, the *Mining Congress Journal* reported the opening of a new metallurgical mine in the East at a cost of about $16.00 per annual ton, which is probably on the high side since it was for metallurgical-quality output. This was annualized at a 15 per cent discount rate over 20 years.

[2] See Richard L. Gordon, *The Competitive Setting of the U.S. Coal Industry, 1946-1980* (forthcoming).

[3] The evidence on reserves of low-sulfur Eastern coal is very poor. Conventional estimates grossly overstate availability by including all coal in the ground, regardless of cost of extraction. On the other hand, a 1967 Bureau of Mines survey, *Analysis of the Availability of Bituminous Coal in Appalachia, 1971*, cited only 4.5 billion tons of recoverable reserves with less than one per cent sulfur being held by producers of more than 100,000 tons per year. Assuming a mine life of 20 years, this could support production of only 225 million tons per year, or 25 million more than at present. The Bureau of Mines figure is undoubtedly an underestimate, since it excludes reserves held by land companies and smaller producers. In addition, what is considered recoverable would increase as prices reached historically high levels. Yet allowance must be made for replacing reserves lost through depletion. The recent difficulty utilities have had in obtaining low-sulfur coal in the East is further evidence of the inelasticity of supply of low-sulfur Eastern coal.

[4] Bureau of Mines, "Cost Analysis of Model Mines for Strip Mining for Coal in the United States," Information Circular 8535, 1972.

[5] A check on this estimate is the 11 to 12 cents estimated in 1970 by the North Central Power Study. (See *North Central Power Study Report* on *Phase I*, October, 1971.) Allowing for approximately 19 per cent inflation in construction costs since 1970, the *North Central Power Study* figure becomes 13 to 14 cents per million B.t.u. in 1973 prices. Recently announced contracts have been in this price range, an indication of negligible royalties and taxes.

[6] The highest published estimate appears to be the $4,000 to $5,600 per acre cited in *Final Environmental Statement, Proposed Plan of Mining and Reclamation for the Big Sky Mine*, Peabody Coal Co., Coal Lease M15965, Colstrip, Montana, p. XII-28.

coal reserves, changes in wages, and changes of transportation rates for coal from Wyoming to the Midwest. In predicting the effect of depletion on cost, the important factor is the "overburden ratio"—the thickness of the removed layers of rock and soil compared to the thickness of the seam of coal that their removal exposes. Bureau of Mines estimates of strippable reserves are based, at least for Western coal, on maintaining the present overburden ratio.[7] Thus, the Bureau estimates that there are about 13.6 billion tons of sub-bituminous coal in the Powder River Basin that could be extracted by strip mining techniques at overburden ratios no greater than is now the case in this area. If we assume that the life of a mine is twenty years, this represents an output of 680 million tons per year before depletion makes it necessary to mine at higher overburden ratios, and thus at increased costs.[8]

Labor costs can also increase, resulting in higher costs for Western coal. To exploit Western resources, workers must be attracted to underpopulated regions of the country. We have not estimated how high wages would have to rise to bring in sufficient labor, but we can examine the effects of higher wages. Using engineering estimates of costs, we separate the total into labor and labor-related costs, and capital costs. The former accounted for 34¢ per ton in 1973. The Union Welfare contribution added 75¢ per ton (it is expected to increase to 80¢ per ton mined in 1974). If all else stays constant in real terms (constant level of productivity and capital costs), we can examine the effect of an increase in real wages by varying the rate of increase of wages and looking at the final cost in cents per million B.t.u. This is done in Table 5.1, which shows that wages do not greatly affect long-run costs in Western mining.

Transportation rates are the third important determinant of the cost of Western coal. They are set by the few railroads that run into the region from the Midwest. Existing rates average 7.5 mills (tenths of a cent) per ton mile, with some in the range of 5 to 5.5 mills per ton mile. Many utilities planning new coal-fired plants are using rates close to five mills to estimate their shipping costs.

There are reasons for arguing that, for a given customer, rates could be either in the range of five mills or in the range of seven to eight mills per ton-mile. It is possible, for example, that new coal-fired plants might initially be charged reduced rates because new coal consumers could move their planned facilities and use another transporter. This bargaining advantage is constrained, however, because a single railroad provides service to most of the coal-producing territory and is assured of a preponderance of the outbound rail movement. Although a lower range of rates per ton mile

	1973	1980, with two per cent annual wage increase	1980, with five per cent annual wage increase
Capital costs	$ .51	$ .51	$ .51
Supplies	.52	.52	52
Welfare contribution	.75	.80	.80
Labor and labor related	.34	.38	.45
Insurance and other	.11	11	.12
Additional reclamation	.28	.28	.28
Total cost per ton	$2.51	$2.60	$2.68
Total cost per million B.t.u.	.148	.153	158

Table 5.1: Western Coal Costs (in dollars per ton) under Alternative Assumptions about the Annual Rate of Wage Increases. The impact of increased labor costs is shown to be minimal. Source: "Cost Analyses of Model Mines for Strip Mining of Coal in the United States," Bureau of Mines Information Circular 8535, 1972, pp. 85-100. All costs were adjusted to reflect the rate of inflation. "Capital costs" were calculated by computing the present discounted value of purchased equipment at a 15 per cent rate of interest. Finally, "labor-related" expenditures refer to items that the Bureau of Mines estimates as a percentage of other expenditures; thus these costs would increase as wages rise.

might prevail for new mining capacity in the next five years, pressures for higher rates to offset increased wage and fuel costs may be expected to nullify the benefits of low "incentive" rates, especially on long hauls to the Midwest. It is also possible that the railroads have quoted unrealistically low rates and that they will together be able to restrict the supply of transportation services through the medium of the Interstate Commerce Commission rate setting practices. Under these conditions, the rates may be closer to 7.5 than to 5.5 mills per ton mile, particularly into the East, where railroads have an interest in protecting the competitive position of Eastern mines.

In Table 5.2 we consider these alternatives by presenting the delivered cost for coal in various cities, using a 15 cent mine-mouth production cost and two different transportation rates. The table indicates the importance of the transportation rate in determining the supply price of coal. It must be expected that under present procedures for setting rates, the higher rates would be in effect and therefore the higher supply prices of coal would prevail.

These considerations lead to a rough but fairly comprehensive picture in which supply prices and levels of production are not greatly different from those prevailing at the present time. The constraints on increased production in the West lie not in a lack of low-cost reserves, but rather in the supplies of input factors between now and 1980. We examine these bottlenecks in the following paragraphs.

Cost-Increasing Factors in the Short-Run

The preceding discussion is based on attempts to find "point estimates" of marginal and average costs of producing coal at normal levels of growth of the industry, and under expected conditions in input factor markets. This provides an approximation of the supply function

[7] See Bureau of Mines, "Strippable Reserves of Bituminous Coal and Lignite in the United States," Information Circular 8531 (1971).

[8] An additional uncertainty with respect to Western reserves is whether the low-sulfur supplies from this region satisfy the environmental standards of the Clean Air Act. The low-B.t.u. content of the coal requires that it have a lower sulfur content than coal with a higher heating value, such as that produced in the East. Because of this uncertainty and other short-run unknowns to be discussed later, we have attempted to be conservative in our estimates of how far coal production in the West can be expanded.

	Chicago	Detroit	East Texas	Phila-delphia
Railroad miles	1,100	1,370	1,500	2,000
Mine-mouth coal per million B.t.u.	$ .15	$ .15	$ .15	$ .15
Transport cost at 5.5 mills per ton-mile	.37	.45	.50	.66
Transport cost at 7.5 mills per ton-mile	.50	.61	.67	.69
Delivered coal at 5.5 mills per ton-mile	.51	.59	.64	.60
Delivered cost at 7.5 mills per ton-mile	**.64**	**.75**	**.81**	**1.03**

Table 5.2: The Cost of Western Coal Delivered to Various Places in 1980. The table uses two transportation rates, to show that this cost has a large effect on the total cost of coal. The higher of the two rates will probably prevail, resulting in the delivered costs shown in boldface type.

for coal—the curve of supply *vs.* price—at levels of "production" in keeping with low rates of expansion of present capacity. To find other points on the supply function involves considering higher levels of production. The marginal and average costs of providing higher rates of production should themselves be higher.

There are a number of potential bottlenecks in the supplies of input factors which could make the cost of providing more production appreciably higher than the estimates shown for normal-growth production. These bottlenecks appear in transportation, mining machinery, environmental and land-use legislation, and manpower.

Potential transportation bottlenecks include limitations on the supply of hopper cars and track necessary to haul large amounts of Western coal into the Midwest. It is likely that by 1980 enough cars could be produced, and enough immediate policy changes could be made, to allow a larger outflow of coal traffic. The measures—such as upgrading roadbeds, improving signaling, adding to siding capacity, and so on—could be undertaken by 1980 and probably would not appreciably increase shipping costs per ton. There are, of course, limits to the process, although no one knows at present what these limits are; prevailing opinion seems to be that with no appreciable increase in cost the traffic could be expanded to more than 200 million tons per year.[9] The willingness of the railroads to make the necessary investments for handling higher traffic volumes would depend on their assessment of its duration and profitability.

A potentially serious bottleneck for the Western coal industry is the availability of mining machinery. Industry representatives indicate that capacity could expand to support a billion tons per year of strip-mined coal by 1985, but rarely does anyone ask what the costs of capital goods for strip-mining operations at this rate of production would be. Yet even at the present time, the industry produces enough machinery each year to add 15 million tons per year to production capacity. Thus without any scale-up, the mining-machinery industry would provide enough for 100 million tons additional yearly output by 1980. Therefore it is likely that more production could be achieved without much higher costs of capital equipment.

There are potential public policy "bottlenecks" as well. They include regulations on reclamation of strip-mined land, whose uncertain costs have been discussed earlier. A typical bill, now being considered by the House Interior Committee, would tax Western strip mining at $2.50 per ton, to provide a fund for reclaiming strip-mined land; this would double the mine-mouth costs of coal, to approximately 30¢ per million B.t.u. The necessary reclamation is yet to be determined. In many areas of the West it would be very difficult to restore the lands completely because of the dry climate, although there have been some successes on an experimental basis. A law that required complete restoration would eliminate some of the potential reserves.

A second policy bottleneck has been a moratorium on leasing the substantial portion of Western coal lands which is owned by the Federal government. Since it takes about three years to develop a mine, substantial increases in output could not be made from these lands until the very late nineteen-seventies, even if the moratorium were ended immediately.

Manpower limits have been discussed above, particularly with respect to mining in the West. If it becomes more difficult than expected to bring men and the necessary support facilities such as living quarters, services, etc., to an underpopulated area, then outputs could be curtailed or costs could increase at an unchanged rate of output. In all, the combination of these bottlenecks and limits on resources could substantially increase the prices necessary to bring forth supplies beyond the amounts forecast above.

Based on the cost estimates made earlier, and considering the various bottlenecks, there should be somewhere near 150 million tons per year of Western coal available by 1980 at prices equivalent to 75¢ per million B.t.u. delivered in Detroit. Assuming that a doubling of costs results from doubling output, then at prices equivalent to $1.50 per million B.t.u. in Detroit, there could be supplies from Western sources totaling as much as 300 million tons per year.

Supplies of High-Sulfur Eastern Coal

Based on our rough estimates for Eastern and Western supplies, the total supply of low-sulfur coal in 1980 could rise as high as 550 million tons per year, which is about equal to current production of high- and low-sulfur coal combined. This suggests that complete reliance on low-sulfur coal may not be possible within the range of prices cited above, and uncertainty about low-sulfur supplies in the East makes it unlikely that government policy will rely on low-sulfur coal alone. High-sulfur Eastern coal will be used, which will involve higher costs—either the implied costs of environmental damage or the costs of installing stack-gas desulfuriza-

[9] This assessment depends upon railroad transportation conditions. There are other transport modes that could be used, such as barging from St. Louis down the Mississippi and up the Ohio River. Yet significant increases in barge traffic would probably congest the locks and increase costs. Slurry pipelining would appear to be limited because of the constraint on water supplies in the arid West.

tion devices. If such devices are not available in 1980, a policy choice will have to be made between the use of high-sulfur coal or very much higher fuel prices.

Reserve statistics indicate the availability of large quantities of high-sulfur coal in the East. These could be available at the *low* end of the price range cited above for low-sulfur Eastern coal, because producers would not have to dig as deeply or mine coal seams as thin as for the low-sulfur coal. At 75¢ per million B.t.u. delivered in Detroit, it is not too optimistic to assume that at least the present rate of 350 million tons per year could be maintained. But this price does not include the social costs of pollution or the costs of sulfur removal. At the conclusion of this section, we will consider supplies of high-sulfur coal at various costs of sulfur removal.

Demand Constraints in the Short-Run

Even if the United States' coal industry could expand its production without limit, the country would be limited in its capacity to use coal in 1980. Based on projections of past consumption, the 1980 demand for coal will be about 700 million tons. Allowing for the greatest possible extent of conversion of electric power plants from oil and gas to coal, demand could rise another 75 million tons by that year. This assumes that 44 per cent of oil plants and 12 per cent of multi-fuel plants could convert to coal (as reported by the Federal Power Commission in *The Potential for Conversion of Oil-fired and Gas-fired Electric Generating Units to Use of Coal*, November 6, 1973). While the calculation is a rough one, it appears that the demands for coal in 1980, based upon capacity to utilize it and upon present technologies, probably would not exceed 800 millions tons per year. This amount is not far greater than the volume expected to be forthcoming in the "point estimates" made above, which assumed normal growth. Thus, although appreciable cost increases could be expected at much higher rates of output, these higher rates may be irrelevant as a result of demand constraints.

Supply Forecast in Tables 2.1 and 2.2

Given all the uncertainties, it is difficult to say with any precision what the supplies of coal will be in 1980. Here we present a basic estimate for conditions of "modest growth" in the coal industry. An attempt is made to present a range of estimates for alternative prices, but only within the demand constraints.

Detroit is taken as a reference market, and it is assumed that coal competes with crude oil there at an equal price per million B.t.u. of energy. Therefore coal priced at 75¢ per million B.t.u. is assumed to be equivalent to oil at $4.50 to $5.00 per barrel. Coal at $1.50 per million B.t.u. is equivalent to oil at $9 to $10 per barrel. Tables 2.1 and 2.2 contain an estimate based on the assumption that some high-sulfur coal is burned. In order to approximate the full costs of using this fuel, it is also assumed that stack-gas desulfurization devices become available.

At present, there is much dispute about whether this technology can be forecast, and what it would finally cost if it were available. The range of estimates is wide, depending upon who makes them and whether the forecaster is talking about existing plants or building new ones. The forecasted costs for fitting existing plants seem to range from 30¢ to 85¢ per million B.t.u. (and at 85¢ this technique could not compete with low-sulfur Western coal today). Tables 2.1 and 2.2 assume that the technology is available at the midpoint of the range—58¢ per million B.t.u.

At $7.00 per barrel oil equivalent, Eastern high-sulfur coal could cost no more than 41¢ per million B.t.u. at the mine-mouth. This is a low price compared to the estimates above, so 1980 supplies of Eastern high-sulfur coal are estimated at 250 million tons, a reduction from the present level of output. Eastern low-sulfur supplies are estimated at 250 million tons, and Western coal at 200 million tons. The total is the equivalent of 7.1 million barrels per day of oil, as shown in Tables 2.1 and 2.2. With stack-gas desulfurization available at 58¢, the earlier cost estimates indicate that at a maximum of $7.68 per barrel ($1.28 per million B.t.u.), substantial amounts of high-sulfur coal could be available.[10] It is not unreasonable to assume that at this price, 300 to 350 million tons would be forthcoming, which, together with the low-sulfur supplies, would approximate the demand-constrained level of 800 million tons, or 8.0 million barrels per day.

It is important to stress that this result depends upon the availability of desulfurization technology at 58¢ per million B.t.u. The market-clearing price could be higher if such devices prove more costly. If they are not available at all, it is likely that sulfur restrictions would not be met, which would involve a social cost that might be reflected in the price, depending on government policy.

These estimates are rough, but a central conclusion emerges. Without low-cost desulfurization techniques, reliance on low-sulfur coal could be very expensive. If, on the other hand, a low-cost desulfurization method is available, coal use can expand quite rapidly—subject only to limits on demand.

The longer the time period, the more the bottlenecks can be overcome. In the short-run, we move along a supply curve that reflects fixed capacity in mining equipment and rail transportation. But in time, adjustments can be made in these capacitities. As we move into the nineteen-eighties, we would expect the output levels discussed in this section to be available at lower costs, and larger outputs to be available at approximately the same costs. The final levels of supply and demand depend crucially on environmental goals in public policy and the ability of the coal industry to supply an environmentally acceptable fuel.

[10] At a wage of $100 per day, in place of the $150 assumed earlier, this coal would become available at about $7.00.

Six: Nuclear Power

The large nuclear reactors presently being built for electric power generation are known as "thermal" reactors, since the fission of uranium or plutonium atoms within them is caused by neutrons which are moderated in energy so as to be nearly in thermal equilibrium with their environment. Water reactors can use either heavy water (deuterium oxide, D_2O) or light water (H_2O) for thermalizing neutrons and removing the energy released by fission; the most prominent U.S. design is the light-water reactor (L.W.R.). An alternative design uses graphite for moderation, and helium gas for a coolant, and is called the high-temperature gas-cooled reactor (H.T.G.R.). Both L.W.R.s and H.T.G.R.s are in use or under construction in the U.S.

Development work is underway on other reactor concepts as well. The liquid-metal-cooled fast breeder reactor (L.M.F.B.R.) is considered by many experts to be the most attractive future design. The system will produce a shower of neutrons sufficient to convert a nonfissionable isotope of uranium into a fissionable isotope of plutonium, as well as causing the fission that ultimately generates electricity. It appears likely that an L.M.F.B.R. can be built which will produce more fissionable material than it consumes—hence the word "breeder." The L.M.F.B.R. has been developed to the point of operation of several demonstration reactors in the U.S. and abroad, and efforts around the world are increasingly focusing on this important concept. More advanced breeder concepts include the gas-cooled fast breeder (G.C.F.B.R.), the light-water breeder (L.W.B.R.), and the molten salt breeder (M.S.B.R.). These systems are in an early research phase, and offer little likelihood of having any impact before the L.M.F.B.R. program.

Light Water Reactors

Figure 6.1 illustrates the present planning schedule for the initiation, design, construction, and startup of a light-water nuclear plant. Clearly no plant orders in 1974 can influence the availability of electric energy in 1980 unless the lead time of ten years is reduced by 40 per cent or more. The principal bottlenecks can be grouped into four categories: initial site analysis, preliminary regulatory matters, construction, and final regulatory matters.

□ *Site Analysis.* The one-and-a-half year process of site analysis and selection cannot be reduced significantly in the next one or two years. Beyond that, however, site analysis delays could be reduced by planning "energy parks," in which a large amount of capacity would be constructed at a single location. The use of platform-mounted offshore nuclear plants might also ease the site problem somewhat. Orders for several offshore plants have already been placed.

□ *Preliminary Regulatory Matters.* Before construction of a new plant can begin, an Environmental Report and Preliminary Safety Analysis must be prepared, and the plant must pass a review by the Atomic Energy Commission. All this takes time, for the environmental and safety studies are presently unique to each plant. Generic review of standardized plant types is being advocated by the nuclear industry. With such a change, and with the preparation of a general environmental report for a single site to be used by many plants, this part of the time scale could be reduced by 50 per cent or more.

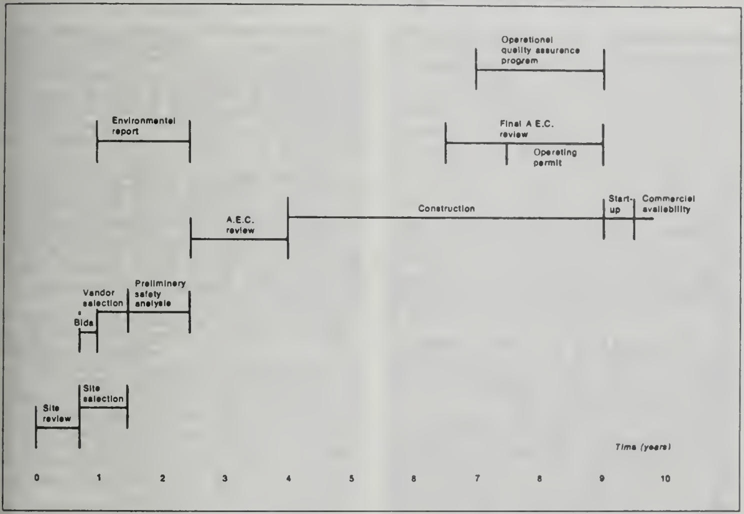
A continuing complication is that any public intervention can presently cause delays of up to a year in hearings on the issuance of a construction permit. The A.E.C. has not been successful, thus far, in streamlining hearings. The problem is under study, but no public date for presenting new guidelines has yet been announced.

□ *Construction.* The current manpower situation is critical. Labor productivity is low due to lack of experience, uniqueness of each plant, and the need for exacting quality control. Most architectural and engineering firms with the capacity to handle nuclear design are severely taxed, as discussed in Section 7 All these factors contribute to construction delays.

There is some hope for improvement. Duke Power does its own construction and claims a four-year construction period—one full year less than is shown in Figure 6.1. Similarly, European and Japanese experience indicates that four-year construction is possible without excessive cost to the utility. Moreover, by standardization of plant design and construction, the experience gained in building a first plant can increase efficiency and lessen construction time for subsequent plants. Despite these potential improvements, however, little gain in the pace of construction is expected in the next few years.

□ *Final Regulatory Matters.* The final review and licensing procedures are not critical factors in the time

Figure 6.1: Planning Schedule for a Light-Water Reactor Plant. It now requires about ten years to plan and construct such a facility for electricity generation. About half of this time is devoted to construction.



scale, since this review proceeds with construction. The process is facilitated by rigorous requirements for quality control during construction which were introduced by the A.E.C. in 1970-71, and strengthened in 1972-73. These requirements are expected to cause difficulties for the next two or three years until experience is gained, but not thereafter. Of course, public intervention is a possible cause of delay at the final stage of plant construction as well as at the start.

Alternative Technology

Experience with the High-Temperature Gas-Cooled Reactor is limited to one small (40 MWe) operating plant, and one moderate sized (330 MWe) plant which will begin operation in the Fall of 1974. Due to limited experience, construction time is longer than that for a light water reactor of similar size, and there is little hope of reduced construction time in the next five to eight years. The H.T.G.R. uses a uranium-carbide fuel array which is very different in composition and construction from L.W.R. fuel elements. Special production and fabrication facilities are needed; plants that produce L.W.R. fuel cannot be adopted to produce H.T.G.R. fuel. A fuel-fabrication plant is under construction, with completion expected by 1978, but it cannot produce more than six reactor cores by 1982.

The breeder program is eight years from a demonstration plant, with an additional ten years before commercial operation. European programs, particularly the French effort, are five to eight years ahead of the U.S. The breeder program is the ultimate nuclear fission energy source, but in the U.S. its influence will not be felt until 1990 or later.

Uranium Resources

Another important factor in a rapid expansion of the nuclear industry is the availability of uranium enrichment capacity. Natural uranium contains over 99 per cent nonfissionable U^{238}; only 0.71 per cent is the fissionable isotope U^{235}. In order to reduce the size and improve the economics of L.W.R.s, it is customary to enrich the U^{235} concentration. The gaseous diffusion process is used by the U.S. and other nuclear powers for enrichment, but gaseous diffusion plants cost billions of dollars. An alternative concept based upon gaseous centrifugal separation has been developed in Europe; plants are now under construction for commercial operation, and orders are being accepted for separative work. Presumably, the process is competitive with gaseous diffusion, but economic details and a time schedule are not available.

The present capacity of America's three diffusion plants is 17.8 million s.w.u. per year (the capacity of enrichment facilities is denoted in "separative work units" or s.w.u.) Projections of nuclear generation in the mid-nineteen-eighties range between 105 and 130 thousand MWe, which will consume up to 16.3 million s.w.u. per year, nearly the present capacity. Short range programs can increase capacity to about 27 million s.w.u. per year. Such capacity will be required by 1985, and thus additional diffusion capacity will be required in the mid-nineteen eighties.

Seven: Synthetic Fuels

Substitute natural gas (SNG), synthetic crude petroleum (syncrude), and methyl alcohol (methanol) can all be produced from coal and from oil shale. Studies of such processes have not been conducted on a large scale in this country until recently, because of the domestic abundance of cheap natural gas and petroleum. Intensive work on coal-based processes was carried out in Europe prior to 1945, however, and it resulted in plants which supplied Germany's wartime fuel needs. After World War II, development in Europe also stopped, because of the availability of cheap foreign crude oil.

As domestic supplies of natural gas and petroleum have lagged over the past few years, interest in synthesis of fuels from coal and shale has revived, resulting in many different processes developed by various organizations. Most of the "second generation" coal-based processes for SNG and syncrude, however, are still in pilot stages at best. Design and construction of large plants, using one of these second generation processes without the benefit of further pilot-plant experience, would involve serious risks. Operations might limp along at a fraction of design capacity, for example, and could thus incur very high costs.

Only for one or two of the new processes could large-scale plant designs be undertaken today with anything approaching confidence. The newer coal-based processes for syncrude are still in their developmental stages. The technologies of methanol synthesis from coal and syncrude synthesis from oil shale appear to be in fair shape, and oil shale studies have progressed to the point where both Union Oil and the Colony Oil Corporation have announced tentative plans for new plants in Colorado, with start-up possible by the end of the decade. Synthesis of SNG directly from oil shale is still in the early developmental stages.

Of course, plants for conversion of coal to syncrude could be designed using the old European technology, which is known to "work." However, these old coal liquefaction processes appear too out-moded to deserve consideration. The old art for making SNG from coal is not severely outmoded, and is being carefully reviewed in this country, even though newer processes under development promise significant improvement.

For most processes, the products produced will find ready market acceptance. The characteristics of SNG match those of natural gas. Syncrude from oil and from coals are acceptable feedstocks for refineries. Coal-derived syncrudes, however, tend to contain a higher proportion of "aromatics" (molecules containing benzene rings), which are valuable for gasoline use, but not as suitable for Diesel fuel. Methanol is a newcomer when viewed as a fuel, and its exact position in the market remains to be established. It could be simply and cheaply converted to methane, and with more difficulty to gasoline. It also could be used as a boiler furnace fuel. Its use as a gasoline additive remains to be evaluated.

The various techniques for making fuels from coal and oil shale are difficult to compare for several reasons. The processes often produce very different mixes of products, for example. Some simultaneously make SNG, syncrude, and a coke-like material called char, in proportions varying from one process to the next, or in proportions which can be varied at will over a considerable range within a single process. Others make primarily SNG, or primarily syncrude.

All the synthesizing processes involve environmental problems. To attain low operating costs, the proposed plants will be enormous in size, and must be located where the necessary combination of coal or shale, water, and transportation facilities are available. Procurement of the necessary process water will be especially difficult in some places, though cooling needs may be moderated by appropriate engineering, and in some situations the mines may yield a significant fraction of the water required. Run-off waters from wastes (ash and spent shale) will carry dissolved salts, which also represent an environmental problem.

The associated mining facilities will be correspondingly large, especially where strip mining is practiced. Large quantities of coal ash or spent oil shale must be disposed of. The coals used will produce five to twenty per cent of their weight in ash, while the spent shale will be 80 to 85 per cent of the raw shale in weight and will occupy a volume up to 50 per cent greater than the shale before oil is extracted from it.

Somewhat arbitrarily, hypothetical SNG plants are generally taken to have a production capacity of 250 million cubic feet per day, consuming perhaps 16,000 tons of bituminous coal daily. One hundred such plants would produce only a third of the country's current gas needs, but would consume all the coal now being mined in the United States. A 40,000 barrel per day syncrude plant, based on coal, is equivalent to a 250 million cubic feet per day SNG plant, in that the heating values of the products produced daily in the two plants are roughly equal. Such a syncrude plant would consume

perhaps ten per cent less coal than the equivalent SNG unit. But one hundred such syncrude plants would produce only about a quarter of the country's current 15 million barrel daily consumption of crude oil.

Costs of Synthetic Fuel Plants

Tables 7.1 and 7.2 show the results of a survey of available information on the costs of fuel synthesizing processes. All costs come from the open literature; due to limitations of time and facilities, no independent cost estimates are presented in this study. The details of the preparation of these data are reported in an Appendix.

To facilitate comparison, all costs in the tables are for plants producing fuel with a heating value of 250×10^9 B.t.u. per day—that is, 250 million cubic feet per day of SNG, 40,000 barrels per day of syncrude, or 12,500 tons per day of methanol. Plant cost estimates made and published in earlier years have been updated to allow for inflation. Plant investments have been put as nearly as possible on an equal basis by including the same allowances for contingencies, start-up, construction loans, etc. These plant investments do not include the mines (except in the case of the shale operations), nor do they include housing for personnel, but otherwise they are complete.

Capital investments are presented in Table 7.1. In view of the great uncertainties in predicting costs—especially the costs of new and unproven technology to be installed in plants of enormous size—these figures cannot be regarded as exact. In such situations, success in predicting capital costs to within 35% is unusual. Further uncertainties are introduced because the original cost estimates were made by different groups whose design philosophies inevitably differed. Finally, the estimates assume that the costs of future construction are adequately represented by estimates in 1973 prices. As noted later in this section, a rapid buildup of investment in these types of facilities could put severe strain on the construction industry, thereby driving up prices.

While recognizing these limitations, it is worth noting that for all processes, predicted capital costs are very similar, falling into a range of \$350 million to \$400 million for the plant size considered.

Typical operating costs for SNG, syncrude, and methanol plants are presented in Table 7.2. These costs are subject to the same kinds of uncertainties as the capital

Process	Capital cost, in millions of 1973 dollars
SNG from coal, old technology	\$400
SNG from coal, new technology	\$300 to 350
SNG from oil shale	\$350
Syncrude from coal	\$350
Syncrude from oil shale	\$450
Methanol from coal	\$350

Table 7.1: Capital Cost of Synthetic Fuel Plants. The figures shown are for the construction of plants that will produce each day fuel with a total heating value of 250×10^9 B.t.u. Estimating costs for large plants using unproven technology is very difficult, yet these estimates indicate that the costs of building different types of synthesizing plants will be roughly equivalent. (The cost shown for the oil-shale processing plant includes an investment in mining and in waste-disposal facilities; the plant alone would cost perhaps \$300 million.)

costs of Figure 7.1. All cost factors such as coal price, labor rates, maintenance expense, taxes and insurance, and so on are charged to the various processes at the same rates, as detailed in the Appendix. The 15 per cent capital charge in these estimates is typical of published costs—it allows ten per cent for return on capital and five per cent for depreciation. But a 15 per cent rate is more representative of utilities financing than of private industry. Any increase, of course, will increase total costs of operation correspondingly.

Of particular note are the clustering of operating costs in the vicinity of \$1.20 to \$1.60 per million B.t.u., the sensitivity of total costs to the costs of coal or shale, and the fact that escalation of construction costs could drastically change these figures. Recognizing all this, it appears that shale oil costs, at around \$1.17 per million B.t.u., are lower than those for the other processes considered.[1]

[1]Due to lack of reliable data, it has not been possible to include comparison of the various *in situ* shale processing techniques now under consideration.

	SNG from coal, using old technology	SNG from coal, using new technology	Syncrude from coal	Syncrude from oil shale	Methanol from coal
Capital, at 15 per cent per year	59	44	51	37	51
Operating costs	22	16	22	22	44
Fuel costs	48	44	37	37	48
Total cost	129	104	110	96	143
Cost per million B.t.u. of product	\$1.56	\$1.26	\$1.33	\$1.17	\$1.73
Cost per barrel (oil equivalent)	\$9.05	\$7.30	\$7.70	\$6.80	\$10.00

Table 7.2: The Annual Operating Cost, in millions of 1973 dollars, of Various Synthesizing Plants, each producing daily a product with a total heating value of 250×10^9 B.t.u. While the predictions are necessarily imprecise, it appears that syncrude from oil shale will be less expensive to produce than the other products shown. (The capital and fuel costs for the oil-shale plant reflect the costs of mining, crushing, and handling raw shale, and disposing of spent shale. The cost of coal is calculated using a price of 32¢ per million B.t.u.)

Synthetic fuel enterprises would be highly capital intensive. A 40,000 barrel per day syncrude plant, for example, would require an investment of around $350 million and, with a product price of $10 per barrel, would have an annual sales income of $130 million. The ratio of capital to annual sales is thus approximately three to one. A similar ratio of plant investment to probable sales income is expected for SNG and methanol. In the chemical industry, however, one dollar of plant investment usually generates about one dollar of annual sales.

In themselves, high ratios of capital to annual sales are not necessarily discouraging. Plants with such ratios are attractive when there is assurance of sales income in future years that is adequate to cover all costs and yield an attractive return. This is attainable only when technological risks which might result in curtailed production are minimal, and when unit sales prices do not fall.

Construction Times for Synthetic Fuel Plants

For coal-based methanol plants and oil shale processing units, it appears that design and construction could be undertaken at an early date with fair confidence that smooth operation would be immediately attainable. SNG plants by old (Lurgi) technology might also be placed in this category, if it were certain that the coal to be used would be processed successfully in the Lurgi reactors (American coals often become sticky, resulting in serious handling difficulties). Planning of SNG plants using the most advanced of the second generation technology could be undertaken in perhaps two years. Syncrude from coal will probably require three to five years of work before plant designs can be undertaken with much confidence. SNG production directly from shale (direct hydrogasification) lies farther in the future.

If the necessary design and pilot data are available, plant construction times are now set at three years. An additional two to three years is normally anticipated to obtain the many permits and straighten out the red tape involved. Demonstration plants for SNG and syncrude should certainly be built soon to explore the problems of synthesis. It would, however, seem undesirable to be stampeded into constructing a large number of such plants based exclusively upon old technology. The argument is often advanced that because of inflation, plants using old technology, built today, will have no higher costs than plants using improved technology, built a few years from now. The flaw appears to be that as a result of such thinking, the country could be saddled with outmoded plants of lower coal or shale efficiency.

In view of the process uncertainties, the scale of the operations involved, and the many difficulties in plant location, it seems unlikely that any significant production of synthetic fuels can be expected much before the mid-nineteen-eighties at best. Even then, a tremendous effort would be required to replace a large fraction of natural gas and petroleum with fuels derived from coal and shale.

The Capacity of the Construction Industry

The volume of construction of nuclear and fossil electric plants, refineries, and other energy facilities needed in the next decade is formidable. If large-scale coal gasification and liquefaction or oil shale processing plants are to be constructed as well, the pressure on particular segments of the construction industry will be tremendous. Prices of inputs to this industry are likely to be forced upward, raising the costs of all these facilities. Bottlenecks will develop (they already exist in some areas), causing construction delays and disruption of orderly planning. Moreover, the cost estimates for new facilities quoted in Tables 7.1 and 7.2 are based on the assumption that construction can be scaled up without difficulty. To the extent that this assumption is incorrect, costs are understated. Unfortunately, the capacity of the construction industry to expand is not well understood at present.

Plant	Years to design and build	Millions of man-hours for engineer/builder: Technical	Manual
1,000 MWe electricity from nuclear fuel	8.5	1.5	11
600 MW electricity from fossil fuel	4.5	.5	3
200,000 bbl/day oil refinery	4	1.5	11
40,000 bbl/day syncrude from oil shale	4	1.0	10
250,000,000 cf/day SNG from coal	5	1.5	10
40,000 bbl/day syncrude from coal	5	1.5	10

Table 7.3: An Indication of the Effort Required to Construct Various Energy Facilities. The figures shown for power generating plants and oil refineries are typical of recent experience; those shown for synthesizing plants are predictions. (Time requirements for the owner and vendors are not included in the man-hour estimates of the rightmost two columns.) When burdens such as these are placed on the construction industry, costs may rise. Thus present estimates of cost may be understated.

To give an impression of the magnitude of the construction task, Table 7.3 draws together some rough figures on the construction of certain electric-power and fuels-processing facilities. The figures for electric power plants and oil refineries are based on current experience and represent typical values. Figures for oil shale, coal gasification, and coal liquefaction are estimates by knowledgeable industry representatives which, because no large-scale units have been built, must be considered as *very* rough—perhaps off by 30 per cent in either direction. Nonetheless, the magnitude of the problems of design and construction are plain.

There are relatively few firms involved in the construction of plants like those listed in Table 7.3. As these firms attempt to scale up to meet requirements for larger volume, problems are likely to develop in three areas: manpower, materials, and machinery.

☐ *Manpower Constraints.* As an example of the pressures already existing and increasing, Stone & Webster Engineering Corp. this year will manage 18 million manual man-hours on the construction of electric power plants. This number will have to triple to 60 million man-hours in 1979 for work already under contract or in negotiation. In its offices, Stone & Webster now employs about 1,800 engineer-draftsmen. This staff must also triple by 1979. The same situation, more or less, holds for Stone & Webster's competitors. According to

Stephen D. Bechtel, chairman of the Bechtel companies: "Our in-house studies show that the growth in skilled craftsmen and the supply of engineers are not keeping up with demand." Bechtel, which is the largest designer and constructor of electric power plants in the U.S., must grow from 20,000 salaried employees today to 50,000 by 1980.

Insofar as engineer-designer manpower is concerned, it does not appear that transfer from aerospace or other industries to plant design is possible for more than a very small fraction of the specialists required. Even transfer between power plant design and petroleum plant design is difficult. Experience appears to be crucial to productivity in process design and development.

One solution to the technical manpower problem is "standardization." The vast majority of plants being designed today are one of a kind, but standardization may well increase in coming years. Yet it is naive to think that the problem will be solved in this way. This is particularly true for unproven technology, where processes and safety requirements change continuously, and where entrepreneurial risks are high.

The most critical trades in plant construction are those that work with steel—pipe fitters, boilermakers, ironworkers, and so on—and electrical installations. One of the most serious bottlenecks appears to be pipefitters. On a 40,000 barrel per day syncrude plant, the contractor will need about 500 pipefitters at the peak. A coincidence of ten such plants under construction could require 5,000 pipefitters. With existing union constraints, a problem exists. To get large numbers of such workers into Montana and Wyoming presents further difficulties.

□ *Materials Problems.* The principal material used in chemical plants is steel: about 170,000 tons go into the tanks, piping, heat exchangers, and so forth in a typical 200,000 barrel per day oil refinery. (We have no firm data but believe that copper—used in all the wiring and electrical equipment—is the next most critical basic material.)

Even today, procurement of steel is a bottleneck in plant projects. For example, the lead time for orders for steel reinforcing bars is greater than one year. Steel pipe also is in very short supply. Certain sizes are not available at all, and the ordering lead time for what is available is increasing rapidly. Some firms are now designing plants that use available pipe sizes rather than optimizing their design.

□ *Vendor Fabricated Items.* In power-plant and oil-refinery design and construction, many major items are designed and fabricated by manufacturers. Examples are valves, compressors, nuclear steam supply systems, boilers, fractionating towers, and so forth. Under current pressures, many vendors are already working at capacity. To increase capacity, they must expand both their fabricating capacity (shop facilities and labor) and their engineering capacity.

Consider, for example, fractionating towers, which might be 60 to 80 feet tall and 12 to 15 feet in diameter, and which have a complicated internal structure. Coal liquefaction plants having a total capacity of one million barrels per day might require 20 or 30 such towers. At the present time only about a half-dozen vendors make them, and each tower might require six to seven months of shop time. A requirement to produce 30 towers in a short period of time would necessitate large capital expenditures in increased shop capacity.

No matter what evolves as government policy, the subsector of the construction industry dealing with plant design, procurement, and construction will be operating under severe stress during the next decade. We have focused here on power plant and chemical plant construction. Similar problems may arise in coal mining, coal transport, and offshore oil drilling. Pressure for significant increases in output will cause critical problems concerning input factors such as process engineers, design engineers, draftsmen, alloy steel, foundries, engineered equipment, pipefitters, electricians, and managers. No analysis is available to show what this pressure will do to the costs of major energy-producing facilities, but there seems little doubt that the more intense the push for domestic fuels, the more likely it is that estimates made in 1973 will understate the actual costs.

Eight: The U.S. and the World Oil Market

The price of imported oil is an important factor in the analysis of U.S. energy policy. The world price determines the resource cost of oil from abroad, and one of the goals of independence is to avoid a large economic drain for energy imports. Moreover, the world price is an important determinant of domestic price, and thus of the incentives to domestic demand and supply.

The world oil price is not determined by the interplay of demand and cost but by a combination of economic factors and the political actions of producer governments. In such a circumstance, the forecaster's lot is not a happy one, and the choice of a policy to con-

	Production		Reserves	
	million bbl./day	per cent	billion barrels	per cent
Western Hemisphere	**16.1**	**28.9**	**76.1**	**13.4**
United States	9.2	16.5	34.8	6.1
Venezuela	3.4	6.0	14.2	2.5
Canada	1.7	3.1	9.7	1.7
Others	1.8	3.3	17.6	3.1
Western Europe	**0.4**	**0.7**	**15.9**	**2.8**
Middle East	**21.4**	**38.3**	**350.3**	**61.7**
Saudi Arabia	7.7	13.6	140.8	24.6
Iran	5.9	10.5	60.2	10.8
Kuwait	3.1	5.8	72.7	12.6
Iraq	2.0	3.5	31.2	5.5
Others	2.7	4.6	45.4	6.0
Africa	**5.8**	**10.5**	**67.8**	**11.9**
Libya	2.2	3.9	25.6	4.5
Nigeria	2.0	3.6	19.9	3.5
Algeria	1.0	1.8	7.4	1.3
Others	0.8	1.1	14.7	2.6
Asia-Pacific	**2.2**	**4.1**	**15.9**	**2.8**
Indonesia	1.3	2.4	10.8	1.9
Others	0.9	1.7	5.1	0.9
Communist Countries	**9.8**	**17.5**	**42.0**	**7.4**
USSR	8.4	15.1	34.6	6.1
China	1.0	1.6	7.4	1.3
Others	0.4	0.7		
World Total	**55.7**	**100**	**567.8**	**100**
O.P.E.C. Members	30.6	55.3	416.3	73.3
A.O.P.E.C. Members	16.4	33.0	299.6	52.6

Table 8.1: World Oil Production and Proved Reserves in 1973. The Middle East is shown to produce over a third of the world's oil, and have close to two-thirds of the world's proved reserves. On the bottom two lines of the table, figures are given for the Organization of Petroleum Exporting Countries and its Arab subset. The source of the data is the *International Economic Report of the President*, January, 1973.

trol imports requires careful study. We will begin with a brief analysis of the world oil price and some of the forces that influence its movement over time. We then turn to a discussion of the possible use of tariffs and quotas to buffer the U.S. economy from the vagaries of this market. Finally, we look at measures, such as stockpiling, that can help soften the impact of any future interruption of the flow of oil imports to the United States.

The Future of World Oil Prices

Oil is the largest single item in international trade, and the markets in which this commerce takes place are diverse and complicated. The principal producing areas are detailed in Table 8.1, which shows that the Western Hemisphere now produces about one-quarter of the world's crude oil. The Persian Gulf currently produces about 38 per cent, and this percentage is growing, since the Gulf countries contain over 60 per cent of the world's proved reserves of crude oil. The principal net importers of oil are the United States, Japan, and the countries of Western Europe. These and other consuming nations face producer governments that are organized into two cartel-like organizations: the Organization of Petroleum Exporting Countries (O.P.E.C.), which contains all the major exporters, and the Organization of Arab Petroleum Exporting Countries (O.A.P.E.C.), which contains the Arab subset of O.P.E.C.[1] At present, the price of oil on the world market is determined by the monopolistic behavior of these exporters.

The pricing arrangements for world oil have evolved over the years into a very complex system. For the purposes of this discussion, however, they were drastically simplified in December, 1973, when the Persian Gulf nations declared a tax of $7.00 per barrel on "own oil"—oil produced by international companies under various concession agreements. (This figure is for a particular type of crude oil. Prices of other crudes are adjusted for quality differentials.) The cost of production in the Persian Gulf is about 10¢ to 20¢ per barrel, and the cost of transport to the U.S. and estimated oil-company profits total about $2.00 per barrel. Thus the price of a company's "own oil" from the Persian Gulf, delivered to the U.S., was a little over $9.00 per barrel as of March 15, 1974. Other exporting countries (which may have production costs higher than 10¢ per barrel, but lower transport costs) adjust their taxes per barrel to follow the lead of Persian Gulf exporters.

In addition to the companies' "own oil" from concessions, there is the so-called "buy-back" oil which the producing nations own, and which they sell to the oil companies. Some producing nations are attempting to collect even higher prices for this part of their output, and as a result oil prices have been extremely uncertain during the first half of 1974, particularly in the Persian Gulf. Oil companies know what tax they pay on "their own" oil, and governments inform them what

[1] The members of O.P.E.C. are Algeria, Ecuador, Indonesia. Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates, and Venezuela. The members of O.A.P.E.C. are Algeria, Bahrain, Egypt, Iraq, Kuwait, Libya, Qatar, Saudi Arabia, and United Arab Emirates.

they must pay for "buy-back" oil, but the proportions of the two are not yet known. At the start of the year, "own" oil was about 75 per cent of production in the Persian Gulf; it will probably turn out to be no more than 50 per cent and could drop to zero before the year is out. Since the settlement of this issue is likely to be retroactive, it is literally true that companies have been selling oil whose cost to them is unknown. In March, companies began transferring oil to their subsidiaries at a price of about $9.50 per barrel, which no doubt includes some allowance for contingencies, and which probably is a level from which the companies expect to retreat.

Our assumption at other points in this study has been that the average payment will converge in the short run on a figure close to $7.00 per barrel. That is, the Persian Gulf nations will be unable, as a group, to agree on any higher price level; their interests diverge on this issue, and Saudi Arabia has publicly opposed any further increases. Under this assumption, the price of Persian Gulf oil delivered to the United States would remain near $9.00 per barrel. Obviously, such a prediction of Persian Gulf oil prices for the near future is no more than our attempt to foresee whatever order may emerge from the current confusion.

Looking farther into the future, the uncertainty inevitably increases. Naturally, the ability of producers to sustain the price at a level many times greater than cost depends on their ability to keep production from outstripping demand at that price—but at this point alternative visions of the future begin to diverge widely. Depending on one's opinion about the ability of the cartel (or key members of the cartel) to restrain production, one can make very different estimates of the future price of oil. If producing nations can perform as a classical cartel and effectively control production, they can sustain any price they desire (subject in the long run to the possible development of substitutes for crude oil). Or, if one country has a sufficiently large share of the market, and is willing to absorb all the required reductions in output (as some argue that Saudi Arabia is), then not even the cartel is needed—one producer alone can sustain the market price above the competitive level.

Analysis of such a situation is difficult, for the essence of a cartel is its unpredictability under strain. Nonetheless, even on very conservative assumptions it can be predicted that the level of strain could become very great between now and 1980. The price in the Persian Gulf has increased nearly eight-fold since 1970, from $1.25 per barrel to the current and uncertain $9.50. (It is important to look back three or four years in considering price increases because of lags in response.) Even if the $9.50 price falls toward $7.00 per barrel, there remains a five- to six-fold increase, to which producers may respond by increasing production. (Taking into account the much smaller rise in transport costs, the price increase at the oil's destinations is roughly four-fold.)

The average growth rate in world petroleum demand from 1962 to 1973 was 7.5 per cent per year. If this pace of growth were to continue through the nineteen-seventies, world oil demand would increase from 55.7 million barrels per day in 1973 to 92.5 million barrels in 1980. But this neglects the effect of the recent

	Production in 1973, in millions of barrels per day	Estimated productive capacity in 1980, in millions of barrels per day
Non-O.P.E.C.	**24.9**	**44.6**
United States	9.2	10.4
North Sea	.0	8.4
Other Non-O.P.E.C.	15.7	27.6
O.P.E.C. "Expansionist" Nations	**12.2**	**17.9**
Algeria	1.0	1.1
Indonesia	1.3	2.0
Iraq	2.0	4.0
Iran	5.9	8.0
Nigeria	2.0	2.8
O.P.E.C. "Conservative" Nations	**18.8**	**24.9**
Venezuela	3.4	3.4
Kuwait	3.1	3.3
Libya	2.2	2.2
Other Persian Gulf	2.2	2.8
Saudi Arabia	7.7	13.2
World Total	**55.7**	**87.4**

Table 8.2: An Estimate of the World's Oil Productive Capacity in 1980. The figures rely on judgments of the price elasticities of supply—in other words, of how much individual nations will increase their production because of an increase in oil prices. The overall forecast is for world productive capacity in 1980 that will be 17 per cent greater than demand.

four-fold increase in prices. On the conservative assumption that the price elasticity of demand is —0.15, this price increase would reduce 1980 demand by about 19 per cent, to 74.9 million barrels per day. (If anything, such a prediction overestimates the demand likely in 1980, since studies of petroleum demand indicate long-run elasticities in the range of —0.2 to —0.4 Moreover, in the current situation, strong and often drastic demand-reduction measures are planned by governments throughout the developed and underdeveloped world—thus adding to the normal price responses of industries and households.)

A rough approximation of what could happen to supply is shown in Table 8.2. The potential U.S. supply is taken from Table 2.1. Other non-O.P.E.C. countries are assumed to have a supply elasticity of 0.35, which is far below the implied coefficient for the U.S. despite this country's status as a special and unfavorable example of increasingly depletion-restricted output. For the North Sea, the estimate is that of an oil company working in the area.

O.P.E.C. producers do not appear to be all alike in their plans and desires for increasing oil output. For purposes of this simple exercise, we divide O.P.E.C. into two rough subgroups: those countries which can be expected to increase output as rapidly as possible—denoted "expansionist" in Table 8.2—and those which will not increase production nearly so rapidly as they are able to—denoted as "conservative." Insofar as possible, the estimates of output in 1980 reflect each country's announced production plans. For the "expansionist" group, the implied price elasticity, for a five-fold price increase, is only 0.24. Outside Saudi Arabia, anticipated production expansion by the "conservative" group is almost nil.

Totalling these rough estimates, world productive

capacity in 1980 is forecast to be 87.4 million barrels per day, which is 12.5 million barrels greater than the forecast demand—an excess of 17 per cent. This excess is approximately 29 per cent of potential O.P.E.C. production. Furthermore, the predicted supplies of 44.6 million barrels per day from non-O.P.E.C. countries and 17.9 million from "expansionist" O.P.E.C. countries leave a market of only 12.4 million barrels per day to be supplied by the "conservative" O.P.E.C. group—a quantity which is actually less than their 1973 sales of 18.6 million barrels per day. In fact, under these assumptions, the "conservative" group could just about meet demands for its production if all but Saudi Arabia held production at 1973 levels, and Saudi Arabia ceased production altogether.

To make this calculation, we have assumed that non-O.P.E.C. oil will be preferred to O.P.E.C. oil in most non-O.P.E.C. countries, so the demand for O.P.E.C. oil could be thought of as the difference between the total world demand and the non-O.P.E.C. supplies. If this and the other assumptions that lie behind the calculation are plausible, then the stability of the current price is questionable so long as Saudi Arabia must be depended upon to exercise all production restraint. In such a situation, Saudi Arabi may well see a somewhat lower price as being in its own interest. On the other hand, it is possible that the cartel could enforce production restraint on all or a significant number of its members. Certainly it is in the interest of all the producers to do so, but the history of commodity cartels does not give grounds for confidence that O.P.E.C. will be successful. Evidence from the recent oil boycott is instructive in this regard. Even under the extreme conditions of the Mideast war, some Arab producers appear to have operated their fields to maximize their own economic interest (which naturally involved selling oil at the newly raised price). Only Saudi Arabia, Kuwait, and Abu Dhabi appear to have exercised significant production restraint.

The primary conclusion to be reached from our thought-experiment is that the range of conceivable values for the world oil price over the next decade is very large. The price could rise above the current level (in 1973 dollars) through the efforts of the dominant exporters. On the other hand, the price could fall, due to the Persian Gulf countries' perceptions of their own long-run interest, or to a sucession of price shadings and a failure of understanding, powerfully aided by attempts of buyers to obtain long-run contracts at lower prices. Rough calculations and study of recent data indicate that the price is more likely to fall than rise over the next few years, but the hard fact is that U.S. policy will have to be set in the face of inescapable uncertainty about this key parameter.

The U.S. can, of course, implement policies to buffer its economy from the world market. It is to these options that we now turn.

Tariffs and Quotas as Instruments of Oil Policy

For any tariff, there is a theoretically equivalent quota. In other words, if one knows the supply and demand responses to price changes, one can predict the level of imports under a certain tariff, and simply allow that quota to enter the country. Even the revenue-creating effect of a tariff can be duplicated by auctioning off the licenses available under a quota, thereby transferring to the U.S. Treasury the same funds which would be collected under a tariff. For oil, however, we lack the information about supply and demand which is necessary to assure the equivalency of particular quotas and tariffs. This lack, of course, is particularly acute with respect to world oil prices, since the overwhelming portion of that price consists of producer-country taxes which could be compressed without making oil unprofitable to sell.

Under these circumstances, tariffs and quotas thought to be the same will have divergent results, depending upon future movements in supply and demand. For instance, if world prices decline unexpectedly, a tariff will result in an unanticipated increase in the percentage of the domestic market supplied by foreign oil, whereas a quota will lead to an increase in the value of an import license but will leave the level of domestic production unaffected. Conversely, the failure of domestic supply to expand as expected will lead under a tariff to an increase in imports, but under a quota will cause an unanticipated price increase for domestic oil.

Under either a tariff or a quota, it is possible to make periodic adjustments as information becomes available. Indeed, except by pure luck, some adjustments will inevitably be required. But the nature of the adjustments will differ under a quota and a tariff, and the political and institutional constraints on adjustment-making will consequently be different.

☐ *Tariffs.* The major advantage of a tariff over a quota is the maintenance of competitive pressure from the world market on domestic prices. When world supply is elastic, any attempt to increase domestic prices is limited by the potential loss of markets to foreign production, and foreign competition remains a spur for domestic efficiency.

A simple tariff, however, cannot limit the country's exposure to imports with assurance. As we have noted, if world prices drop, imports will be greater than expected and domestic production will decrease. This particular difficulty can be avoided through some sort of variable tariff, which could be set at the difference between some targeted domestic price and a base foreign price—for example, the average tax-paid cost of crude oil at the Persian Gulf, adjusted by a standard transportation cost. But this converts the tariff from a device that puts a price ceiling on domestic production to a device that sets a price floor. Doing so removes the competitive pressure of imports and thus neutralizes the major advantage of the tariff.

From a security point of view a variable tariff is also weak, for two additional reasons. First, it still does not protect the country from an undue penetration of imports if either the domestic supply or demand curve is mis-estimated. (This problem can be avoided by raising the tariff to achieve a targeted import level, but this makes it a disguised quota.) Secondly, adjustment as information becomes available may prove politically difficult: downward adjustment will cause protests by oil producers, and upward adjustments will cause protests by consumers. As a result, changes are likely to be delayed, and inertia may prevent any change at all. Political resistance might be avoided if the tariff were levied as a formula (like the

one mentioned in the last paragraph) rather than a dollar figure, and recalculated regularly. A formula, however, could not take care of errors in the estimation of domestic production and demand unless it was expressed in terms of import volumes, in which case the tariff again becomes a quota.

A variable tariff which establishes a floor for domestic prices might have an advantage over a quota, to the extent that is gives domestic producers a clearer guide to the future course of domestic prices, and thus gives them greater certainty in evaluating their investment prospects. A quota that is apparently equivalent to a particular tariff in its protective effect may not result in the same level of investment, if firms are risk-adverse.

□ *Quotas*. The major advantage of a quota is its ability to limit directly the country's exposure to foreign oil. An oil import quota was in effect in the U.S. from 1959 until the early nineteen-seventies, but it was defective for a number of reasons. First, the quotas were imposed in a time when domestic production was heavily influenced by the "market demand prorationing" practiced by major oil-producing states—most notably Texas, through the regulatory actions of the Texas Railroad Commission. Under prorationing, these states were able to fix the total output by assigning a production quota to every well within their borders. Thus, in effect, control of U.S. oil prices passed to the Texas Commission, which attempted to manage output in order to maintain prices. This created substantial excess capacity and inefficiencies in domestic production. Secondly, the import licenses were distributed to refineries in a fashion that provided limited benefit to consumers and no revenue to the Treasury. Finally, the quotas were subject to a large number of exceptions unrelated to security objectives.

It is possible to have a pure quota which is not subject to these defects. Under such a quota, import rights would be auctioned off to buyers periodically, the revenues from the auction accruing to the Treasury. Anyone could buy licenses, and they could be resold. Since various middlemen could be involved in these transactions, it might be possible for the true identity of any buyer to be kept secret, in case he wished to evade an agreement not to bid. Both long-term and short-term quotas could be sold; the former would allow importers to make investment decisions with assured access to the U.S. market, and the latter would take care of the needs of the spot market.

One of the advantages of a secret competitive auction of import licenses is its potential for capturing some of the monopoly rents now being paid to the exporting countries. Bidders for import rights who must themselves purchase oil will bid only the difference between world and U.S. prices. Producer governments, on the other hand, could bid more, under threat of losing sales in the U.S. market, and transfer the licenses to producing companies. The true cost of oil to most exporting governments, particularly those in the Persian Gulf, is near nothing, and the cost to national oil companies is only 10¢ to $1.00 per barrel. Sales in the United States could be enormously profitable, and thus the national companies could afford to bid an amount for import rights that is greater than the spread between world and domestic prices.

The described bidding procedure has more general advantages. If offers the prospect of capturing more rents for the Treasury than would a tariff (which of necessity would be set at the difference between the world and domestic prices). It also encourages competition among O.P.E.C. members, and any competition could put stress on the cartel and in the long run lead to an erosion of prices. Even if competition for the U.S. market does not emerge, the quota would produce the same revenue as a tariff.

One problem with a quota has been the difficulty of enforcing it when there is upward pressure on domestic prices. Conversely, there may be pressure to tighten the quota if domestic prices begin to fall. From 1971 to 1973, at least, the U.S. government found it easier to relax the quota than to meet the political pressures caused by a price increase. This may have been due to the historical use of the quota to protect producers, and to the presence in the early part of this period of excess capacity created by market demand prorationing, which made the necessity of a price increase look suspect. The recent crisis may make consumers more tolerant of price increases if they are necessary to limit imports. Nevertheless, this historical weakness should be noted.

□ *Security Penalties*. Even with a quota, it is possible to favor production from certain countries. Particularly secure sources of supply, such as Canada, could be exempted entirely, but doing so would allow either the Canadian government (through an export tax) or Canadian producers (through increased prices) to capture all of the difference between U.S. and world prices. There is no apparent need for the United States to be so generous. Even when U.S. and world prices are equal, Canadian oil can earn more in the United States than abroad because of the cost of transport.

Imports from sources deemed insecure could be charged a security fee. In the short-run, when all supply sources are fixed, the fee could be avoided through exchanges among importers, substituting oil from "secure sources" for oil from "insecure sources." Such exchanges would not affect world output or the incomes of particular countries. But in the longer run, the burden of the fee would fall upon the producing country if competition for the U.S. market by national companies develops, or if there is insufficient oil from secure sources to satisfy the quota. In light of the large rents currently incorporated in world oil prices, an insecure country could still find it profitable to bid for access to the U.S. market, but to do so the country would be forced to share an even larger part of the rent with the U.S. Treasury.

If the fee were emulated by other consuming countries, its impact would be greater. In that case, even if there were no competition among producing countries for incremental sales, oil from countries deemed insecure would suffer a disadvantage if importing countries not imposing the fee were inadequate to absorb the desired level of production by insecure sources. As long as the supply of oil from countries considered secure was elastic, the burden of the fee would fall upon the producing country. The same effect could be achieved under a tariff system by setting different tariff levels for oil from secure and insecure sources.

Petroleum Stockpiles

Whatever policies are followed, the United States will be importing petroleum from potentially insecure sources for the remainder of the decade, and there is a good chance that such imports will continue for many years beyond that. Several measures could be taken to increase the flexibility of the country to deal with disruption of supply from the international market. They include emergency preparedness for curtailing consumption of petroleum products, measures to increase our capacity to convert from petroleum to other fuels during a disruption, provision for emergency increases in petroleum production from domestic reserves, and stockpiling of emergency supplies. All these precautionary actions deserve careful study. Their potential importance as elements of the U.S. relation to the world oil market can be seen in a very brief assessment of one of these measures—stockpiles.

The U.S. alone among major industrial nations has no provision for stockpiling crude oil beyond normal inventories. (It does maintain strategic stockpiles of many other natural resources, especially metals.) Our analysis suggests that stockpiling could be an important component of overall U.S. policy for ensuring a steady supply of energy. It would permit the U.S. to take advantage of a lower world price of oil without the costs and risks of relying on the timely arrival of imports.

The size of the stockpile depends on the magnitude of the expected interruptions and on the volume of imports permitted. For the sake of discussion, we will outline a "low" stockpile program that would permit a level of dependence of 15 to 20 per cent on imports and complement other policies for achieving independence, and a "high" stockpile program that would permit unrestricted importation and would be the sole federal policy for independence. In both cases, we measure the costs of the programs at current prices and current levels of energy consumption. Future costs would rise in proportion to changes in these two numbers.

☐ *The Low Stockpile.* Here we assume that some form of tariffs and import quotas, coupled with a stimulus to domestic production, serve to reduce U.S. imports to about 4 million barrels per day, and that half of this comes from insecure sources. We further assume that replacement of insecure sources may take approximately one year. Under these conditions, the stockpile should be about 730 million barrels. Estimated costs per barrel of above-ground storage facilities range between $3.00 and $5.00; costs for storage in underground cavities, such as salt domes, are about $1.00 per barrel. Some mix of these two types of facilities could be used in any large-scale stockpile program, and therefore the overall average construction cost for storage facilities should be approximately $3.00 per barrel. We further assume an annual operating cost of 10¢ per barrel, and that the oil itself would cost $8.00 per barrel. Taking interest and depreciation of the facilities as 15 per cent per year, and interest on the oil as ten per cent per year, we find a total carrying cost of $1.35 per barrel per year. The annual cost of the low stockpile would therefore be $990 million.

European countries administer stockpiles by requiring oil companies to maintain them as a condition for the right to sell petroleum products. If this approach were adopted in the U.S., costs of oil companies would rise by about 26¢ per barrel of products sold, or about two-thirds of a cent per gallon. Alternatively, the storage requirement might be imposed on the importers of oil, in which case their costs, and prices, would rise by about 1.6¢ per gallon.

The low stockpile would require the construction of facilities costing $2.2 billion, phased over a few years. The construction methods required are conventional and should place little strain on the construction industry.

☐ *The High Stockpile.* Here we assume imports of 4 million barrels per day from insecure sources, and assume further that three years would be required to develop alternative sources in the case of an interruption. The high stockpile would make the cost of interruptions like the recent embargo extremely high to the producing country, since it would forgo all revenues from the U.S. for three years before the interruption imposed any penalty on this country. The cost of this program is approximately six times the cost of the low program, or $5.9 billion per year—perhaps somewhat more, because of the strain it would impose on the construction industry. Construction of the facilities and accumulation of oil would be phased over a longer period than for the low program. Costs and prices for all petroleum products in the U.S. would rise by $1.56 per barrel on the average, or 3.7¢ per gallon.

The cost of the high stockpile program compares favorably with the alternative of eliminating dependence on imports. Under the high stockpile program (with no restriction on imports), the price of oil would be $8.56 if the world price were $7.00, whereas the U.S. price under import prohibition could be as high as $12.00. Consumers would save $3.44 per barrel, or about 8.5¢ per gallon. Moreover, U.S. natural resources would be conserved for later use when cheap foreign sources may be exhausted.

Many issues remain to be resolved about how such an emergency stockpile might be developed and managed, both in normal times and in an emergency. Nonetheless, the costs are sufficiently low, in relation to the likely costs of complete energy self-sufficiency, that this possibility deserves careful consideration.

Nine: Policy Conclusions

Two goals underlie the emerging set of Administration policies that have been termed "Project Independence":

□ Reducing the risk and the cost of disruption of oil imports, and the attendant effects on foreign policy and the domestic economy.

□ Freeing the U.S. from the burden of high-priced oil imports, if the cost of imports is higher than the cost of increased domestic supplies.

Much discussion of Project Independence treats these goals as if they were one, but they are not necessarily even compatible. For example, if domestic supplies do not increase appreciably when the price rises, or if world oil prices decrease, then self-sufficiency could be bought only at the cost of an increase in prices *over* what might well be the long-term normal price of imports. In such a situation, the choice of policy measures depends on the relative importance attached to the two goals and on judgments about the critical uncertainties named in Section 1.

In many areas, very difficult choices must be made in the face of these uncertainties:

□ The way we normally solve domestic shortages is to let higher prices (perhaps supported by tariffs or quotas) suppress demand and bring forth increased domestic supplies. But because of the size of the energy industry and the magnitude of contemplated price increases, allowing these market forces to operate will involve significant transfers of income from consumers to the owners of energy-related assets.

□ Rapid development and utilization of coal will run into conflict with recent gains in the field of environmental protection.

□ The more quickly we try to achieve "independence," however it is defined, the greater will be the cost, in both economic resources and in environmental degradation.

In the face of such difficulties, the determination of firm policies requires analysis beyond that which we have been able to accomplish, and social judgments that ultimately must be made by responsible public officials. Nevertheless, the available information and our analysis of it reveal important features of the energy problem, and the policies that are likely to prove most effective and equitable in dealing with it. These measures fall into four areas: corrections to current federal regulatory policies; actions to let the market work effectively; actions to redress adverse effects on income distribution; and provision of security against disruption of oil imports, whatever the import volume may be.

Seek Revisions in Current Regulatory Policies

Many aspects of federal and state law and regulatory procedure serve to retard the growth of energy supplies and encourage the waste of energy. A continuing effort should be devoted to ferreting out these situations and, where possible, correcting them, even without the pressure of Project Independence. Naturally, most regulations have a good reason for existing, or had at their inception, and change usually runs into conflict with the interests of particular groups or with some broader public concern. In several areas, revision will come with difficulty if at all, but they deserve to be noted nonetheless.

□ *Field Regulation of Natural Gas Prices*. Under current law and regulatory procedure, natural gas is seriously underpriced, leading to wasteful consumption and a reduction of supply incentive. Tables 4.1, 4.2, and 4.3 make clear the importance of correcting this imbalance. Field price regulation should be eliminated in phases over the next five years, along lines discussed in Section 4, as has been proposed in both the House and Senate in the last year. This change could make an important contribution to any program to approach energy independence.

□ *Railroad Rate Regulation*. One key to the effective use of Western low-sulfur coal is the price of this coal delivered to markets in the East and Midwest. The outcome of rate cases under Interstate Commerce Commission jurisdiction can have a significant effect on this price. If, under the pressure of increased coal traffic, rates are allowed to rise too high (perhaps in order to subsidize other less profitable rail operations), coal use will be penalized and substitution of coal for oil and gas will be retarded.

□ *Leasing of Federal Lands*. By far the greatest increase in domestic energy supplies between now and the early nineteen-eighties will come from sources under federal jurisdiction, including offshore oil and gas,

Alaskan oil and gas, and Western coal. Given the long lead times for exploration and development, it is important that lease availability itself not continue to be a constraint, particularly in the case of offshore oil. The key here appears to be a rapid resolution of disputes over the adequacy of environmental safeguards.

☐ *Sulfur Pollution Standards*. Beyond these first four issues lies a direct and unavoidable confrontation between the Clean Air Act (and associated implementation plans) and any scheme to substitute Eastern coal for oil and gas. There is even doubt about the environmental consequences of burning much of the *low*-sulfur coal available in the West. Effective stack-gas desulfurization at a reasonable cost would cut the Gordian knot, but progress in this area is not a certainty. Our studies have not included analysis of the ways in which the Clean Air Act might be modified to allow increased coal use, yet preserve desired quality standards in our ambient air. It is clear, however, that any move away from current procedures will require much greater attention to ambient monitoring and to flexible systems of fuel control.

☐ *Licensing of Nuclear Power Plants*. The present time cycle required for the design, certification, and construction of nuclear power plants affects the rate at which nuclear power can be substituted for the use of fossil fuels. As discussed in Section 6, changes in regulations to speed the approval process and decrease construction delays and costs are possible and needed.

Allow the Market to Work at Current International Prices

When the current confusion about Persian Gulf oil prices is clarified, the price for 1973 will probably turn out to be a little over $7.00 per barrel. With the addition of transportation cost and producer's profit, the cost delivered to the U.S. East Coast will be over $9.00 per barrel. It is argued in Section 8 that it is unlikely—though certainly not impossible—that the price of world oil to the U.S. will rise above this level in the next few years. It seems more likely—though far from certain—that the prices in 1973 dollars will decline from the $9.00 level over the rest of the decade. Although it is hard to imagine the price dropping below $5.00 to $6.00 per barrel, there is no meaningful price floor set by the actual cost of oil, which is less than five per cent of current import prices.

The price of Persian Gulf oil delivered to the U.S. was about $4.00 per barrel just one year ago, and therefore the production incentive offered by future prices over most of the expected range is very great. The question is how best to design a policy to take advantage of those forces when they work well, and what to do if even this incentive proves inadequate.

☐ *Price Maintenance*. One way to strive for energy independence would be to use flexible tariffs or quotas to hold the oil price at a level that would clear domestic markets without (or nearly without) imports by the early nineteen-eighties. The analysis of Section 2 shows that it well might require a price above $11.00 per barrel to achieve this. This is an extremely high price, and policies that lead to it probably cannot be sustained. Given the purely technical limits on development of substitute fuels, even with large subsidies, it is unlikely that "independence" can be attained by the early nineteen-eighties if it is defined in terms of a zero-net import requirement.

However, even if the import price cannot be raised to a market-clearing level, the question remains: Should the price of imported oil be held at some level above the expected import price of $9.00—say, at $10.00 to $12.00 per barrel? Our conclusion is that it should not, for the following reasons:

The current import price, and the price of "new" oil,[1] which follows it, are high enough to provide adequate incentive for oil exploration. (Natural gas is a separate problem, as noted in Section 4.) A still higher price will have only a marginal effect on exploration and production over the next few years.

At the current price level for imports, and the associated price of residual fuel oil, there is also ample incentive for coal production. At this price, the most immediate barriers to expansion of coal are to be found in environmental issues, in problems of transportation and government leasing policy, and in limited demand.

As indicated in Section 7, no one knows with any accuracy what price incentives it may take to spur development of synthetic fuels, or whether incentives are needed at all. Therefore, in the early stage of this new industry it is preferable to use selective policy instruments, such as specific plant process or product guarantees or subsidies, which are more precisely atuned to the problems of large-scale synthetic fuel processes.

The effect on demand of a $9.00 energy price is poorly understood, and even less is known about prices above that level. In the short run, such a price would yield little other than an income transfer from consumers to producers. The political difficulties that flow from these income transfers need no elaboration.

In short, the import price is high enough, and there is little to be gained from raising it higher. Should the world price rise still higher due to actions of exporting countries, this conclusion is only strengthened.

☐ *Protection Against Down-Side Risk*. Should the real price of imports (in constant 1973 dollars) begin to fall below the expected $9.00 level, another set of questions arises. Should a floor be put under import price by flexible tariffs or quotas? If so, at what level? Further, should that floor be established now, or can this possibility be left an open question? Our conclusions are the following:

By the same arguments as those used in the paragraphs on "Price Maintenance," there should be adequate incentives for oil, gas, and coal supply at prices as low as $7.00 per barrel, and therefore there is little need at this time to set a floor on import price, provided that proper incentives are offered to the infant synthetics industry. Should the import price drop into the neighborhood of $7.00 per barrel, this conclusion would have to be reconsidered. In addition, more data will become available on supply and demand response to current high price levels, and this judgment can be adjusted in the light of that new evidence as well.

As noted in Section 8, the choice between tariffs and

[1] "New" oil includes all oil from wells completed since 1971, or from increases since 1971 in production from pre-existing wells. "Old" oil, which remains under price control, is the remainder of domestic production.

quotas is a complex one in the new world-oil situation. There is a clear need for further in-depth study of these measures, and evaluation of their flexibility in the face of the inevitable uncertainty in the world oil market over the years to come.

□ *Domestic Price Controls*. Domestic "old" oil is currently being held at $5.25 per barrel, while "new" oil is selling at $9.00 or above. Under current definitions, "new" oil is about 30 per cent of total domestic supply, and that percentage will grow with time. Such a two-tier pricing system leads to distortion and waste when applied to essentially the same product, especially when new investment in old oil leases is desirable. On the other hand, removal of price controls will result in a sizable increase in revenues and profits to certain segments of the petroleum industry. (Similar problems arise from price controls on gas.)

In this circumstance, we recommend that price regulation of "old" oil be relaxed (perhaps in phases), but that this be done only if provision is made to capture a portion of the resulting income transfers, by means to be discussed momentarily.

□ *Incentives to the Synthetics Industry*. Thus far, we have argued that no commitment should be made to hold the price of energy high enough to make room for SNG, syncrude, methanol, or shale oil. But if this approach is taken, some specific programs will be needed for these sources, since their development to pilot and commercial productions stages should not be delayed.

The best way to accomplish this is to identify a special class of new energy sources, and provide specific price guarantees for the output of the first group of commercial-scale plants. In a few years, a great deal more will be known about the synthesizing processes, and better informed judgments can be made about their costs and the general price level it takes to give incentive for their expansion. To handle the first round of plants, one of two schemes is recommended:

One: Potential synthetics suppliers bid for contracts to supply SNG or syncrude to the federal government at some future date. Contracts would be in lots of, say, 50,000 barrels per day, and would be at a fixed price per barrel (plus adjustment for inflation) for an adequate period of years (ten to 20). Through this bidding process, it can be determined whether and how much subsidy is required.

Two: The federal government offers to purchase oil from new commercial plants at a price agreed upon by negotiation.

Many details of such schemes remain to be analyzed. But by moving now to offer a price floor for the critical first generation of plants—up to perhaps 500,000 or a million barrels per day equivalent—the federal government can insure that development takes place at the maximum rate without a premature commitment to subsidize or otherwise provide protection for a massive industry as yet unborn.

□ *Measures to Increase Energy Productivity*. There undoubtedly are many places in the economy where energy is not utilized efficiently, even at increased prices, due to some failure in the working of the market mechanism. The savings to be gained from correcting these failures by selective public measures should be considerable, and a continuing effort should be made to isolate these cases and, where possible, to treat them.

Correct Adverse Effects on Income Distribution

When the price of world oil is driven up very rapidly by action of foreign producers, it is inevitable that there will be an accompanying rise in the revenues and profits accruing to persons owning energy-producing assets of one kind or another. Several of the policies recommended above—such as natural gas deregulation and relaxation of domestic price controls on "old" oil—will contribute to this income transfer. The amounts of money involved are large enough to raise real problems of social equity. For example, a $5.00 price increase on 10 million barrels per day of domestic oil and gas amounts to an income transfer of $18 billion per year. Current political controversies over crude oil prices are, in large part, a reflection of this underlying equity issue.

Several solutions to this problem have been proposed, including a variable excise tax on domestic crude oil and various forms of excess-profits taxes. The best answer, however, is apparently to bring oil companies back into the U.S. corporate income tax system. At present, with foreign taxes (which run in the neighborhood of $7.00 per barrel) being credited against U.S. taxes on overseas operations, and with the 22 per cent depletion allowance, the corporate tax liability of many oil companies is vanishingly small. We have not conducted an analysis of the details of alternative changes to the special provisions of the tax code for various parts of the energy industry, but the simplest and most straightforward solution seems to be to treat energy corporations more nearly like we treat the rest of American industry, and thereby to capture some of the rising income flows in the normal tax system.

With such a change, two questions would remain: Is the income transfer, after taxes, sufficiently reduced to prove socially acceptable? And are corporations left with sufficient retained earnings to finance needed investments? We suspect that the answer is yes, but both issues need further study.

Provide Security Against Import Disruption

Implicit in the preceding conclusions is the judgment that the cost of security is too high if it is sought solely by eliminating imports. In effect, the two justifications for independence from foreign sources—avoiding oil blackmail and cutting the resource cost of our energy—are contradictory if the target date is the early nineteen-eighties. The economic cost of additional domestic supplies, on this time scale, is above the expected economic cost of imports. As a result, the U.S is likely to be a net importer of energy right through the nineteen-eighties, though in drastically reduced quantities, as a result of the policies discussed above. The question is how to reduce the risk of these residual imports.

Far too little attention has been given to the possibilities and costs of providing a stockpile of crude oil beyond normal inventories. While we have not examined the possible response of O.P.E.C. to this program, or the best means of insuring that inventories are built up to the desired level, we believe that this option must be given serious consideration as another way of reducing the risks and costs of interruptions in our energy supplies.

Appendix: The Origin of Synthetic Fuel Costs

Table A.1 (next page) presents data taken directly from the open literature on the various synthetic fuel processes. Only the total capital investment figures have been altered, we give them in 1973 dollars. Coal costs are standardized to 32¢ per million B.t.u. for Eastern bituminous coal ($8.00 per ton at 25 million B.t.u. per ton), and 16¢ per million B.t.u. for Western coal ($3.00 per ton at 18.75 million B.t.u. per ton). Plant costs are for a completely self-contained unit, and include everything except cost of the mine (unless otherwise noted) and housing facilities for workers.

Four different estimates for Lurgi-type coal gasification plants appear in the table. They show significant variations in capital costs and efficiency, even though the plants have the same capacity, and are based on the same technology. Details on the estimating procedures used are scanty, so reconciliation of the differences is not possible. It is probable, though, that Fluor's estimate, being the most recent, is the most reliable. (Here it should be noted that the tar by-product is apparently not credited to the operating cost or to the coal consumed.)

The second group of processes presented in Table A.1 are those coal liquefaction processes for which cost estimates are available: H-Coal, PAMCO, COED, and CONSOL. Note that the capacities of these plants differ widely, as do their mixes of products. Costs for only one methanol plant were found in the literature, as presented in Table A.1.

Published data on projected costs of the oil-shale processes are likewise scarce. The costs of syncrude obtained from shale liquefaction obviously depends on the assay of shale used, and are five to seven per cent lower for material containing 35 gallons per ton than for 25-gallon-per-ton material. Processing costs depend significantly on the cost of disposing of spent shale, apparently assumed in these estimates to be nominal.

The data in Table A.1 are presented in condensed form in Table A.2 (page 58), after the following recalculations to simplify process comparisons:

☐ Plant sizes differ by a factor of three in Table A.1. Investments in these plants have been scaled to a capacity of 250×10^9 B.t.u. per day in Table A.2 by assuming investments to vary with the 0.9 power of capacity. This exponent is conservative and assumes that, for large plants, capacity increases are made by multiplication of units. Before such scaling, all plant costs are corrected to 1973 dollars using the *Chemical Engineering Plant Cost Index.*

☐ Total capital investment has been standardized to include the same facilities, such as power generation and pollution control capabilities. Capital costs exclude the mine except where indicated. These investment figures also include 15 per cent for contingencies.

☐ Operating costs are similarly standardized. Thus coal, labor, taxes, and insurance are charged to all processes at the same rates, as detailed in the footnotes to Table A.2. The plants are assumed to operate 330 days per year.

Facing page:
Table A.I: Plant Costs for Various Synthetic Fuels, at 1973 prices. All data are taken from the open literature. The sources are the following:

"Final Report—The Supply-Technical Advisory Task Force—Synthetic Gas-Coal" National Gas Survey, Federal Power Commission, April, 1973.

"U.S. Energy Outlook—Coal Availability," Report of the Fuel Task Group on Coal Availability, National Petroleum Council, 1973.

"Evaluation of Coal Gasification Technology; Part I, Pipeline-Quality Gas," National Academy of Engineering, 1972.

"Evaluation of Coal Gasification Technology; Part II, Low- and Intermediate-B.t.u. Fuel Gases," National Academy of Engineering, 1973.

Wen, C. Y., "Optimization of Coal Gasification Processes," R & D Report No. 66, Office of Coal Research, 1972.

Siegel, H. M. and T. Kalina, "Technology and Cost of Coal Gasification," *Mech. Engr.*, May, 1973, pp. 23-28.

Moe, J. M., "SNG from Coal via the Lurgi Gasification Process," Symposium on "Clean Fuels Firm Loaf," Institute of Gas Technology, Chicago, Ill., Sept. 10-14, 1973.

Shearer, H. A., "The COED Process Plus Char Gasification," *Chem. Engr. Prog.* 69 (3), 43 (1973).

Foster-Wheeler Corp., "Engineering Evaluation and Review of CONSOL Synthetic Fuel Process," R & D Report No. 70, Office of Coal Research, February, 1972.

Michel, J. W., "Hydrogen and Synthetic Fuels for the Future," 166th Nat. Meeting, Amer. Chem. Soc., Div. of Fuel Chem. Preprints, *18*, No. 3, August, 1973.

"U.S. Energy Outlook—Oil Shale Availability," National Petroleum Council, 1973.

	Output fuel (billion B.t.u./day)	Daily plant output	Input fuel (tons/day)	Thermal efficiency (per cent)	Total capital investment ($ millions)			Annual operating costs ($ million)			Capital charge, 15% TCI/year (cents per million B.t.u. of product)	Operating cost (cents per million B.t.u. of product)	Coal cost (cents per million B.t.u. of product)	Product cost (cents per million B.t.u.)
Coal gasification														
F P.C. Lurgi—bituminous	237 2	250 million c.f. pipeline gas	16,000	59.2	347			23.1			66.5	29.5	54.1	150.1
F P.C. New—bituminous	240.0	250 million c.f. pipeline gas	15,900	60 3	296			16.2			56.1	20.5	53.1	129 7
F P.C. Lurgi—Western	238 6	250 million c f. pipeline gas	20,800	61.2	313			24.6			59.6	31 2	26 1	116 9
F P C. New—Western	240 0	250 million c f. pipeline gas	21,200	60.3	261			16.1			49.4	20.3	26.5	96.2
N P.C. Lurgi—bituminous	243 0	270 million c.f. pipeline gas	14,300	67 9	265			20.6			53.3	25 9	47.1	126 3
N P.C. Lurgi—Western	243.0	270 million c.f. pipeline gas	19,200	67.6	241			18 6			45.1	23 2	23.6	91 9
N A E Lurgi	235 0	240 million c.f. pipeline gas			316						61.5			
Fluor Lurgi—Western	252.1	257 million c.f. pipeline gas	23,900	56 2	427						77 0	24.5	26 5	130 0
Coal liquefaction														
N.P C. H-Coal—bituminous	240 0	30,000 bbl syncrude 60 billion B.t.u. fuel gas	13,000	74	260			26 6 excl. coal			49.2	33 9	43 2	126 3
N.P.C. PAMCO—bituminous	180 0	30,000 bbl. "de-ashed prod."	9,600	75	187			13 4 excl. coal			47.2	22.6	42.7	112.5
Amoco COED—bituminous	405 0	250 million c.f. pipeline gas 29,175 bbl. syncrude	28,400	57	500			53.6 excl. coal			56.0	40.0	56.0	152.0
Foster-Wheeler CONSOL A-Bit	358 8	284 3 billion B t.u. liquid 74 5 billion B.t.u. gas	20,200	71	309			36.0 excl. coal			39.1	30.4	45.1	114 6
Foster-Wheeler CONSOL B-Bit	421 0	282 1 billion B.t.u. liquid 138 9 billion B t.u. gas	25,100	67	405			43.3 excl. coal			43.7	31 2	47 6	122.7
Low-B t u.-gas from bit. coal														
N A E.—150-400 B.t.u./c.f.	235.0		11,800-13,400	70-80	165-169						31.9-36 6		40.0-45.7	110-125
F P.C —150-400 B.t.u /c.f.	235 0		11,800-13,400	70-80	169-191						36 6-36.9			
Methanol from coal														
ORNL—bituminous	391	20,000 tons methanol	23,300	67	416			58 4 excl. coal			46 4	45 3	47 8	141.5
Oil shale					*Process*	*Mine*	*Total*	*Process*	*Mine*	*Total*				
F P C gasification—25 gal /ton	250	271 million c f. pipeline gas	94,500	74	292	156	448	20.6	22.6	43.4				133
N P C. liquefaction—25 gal./ton	600	100,000 bbl. syncrude	174,800	96	542 542	210 250	752 792	44 44	46 50	90 94				102-106
N P C liquefaction—35 gal./ton	600	100,000 bbl syncrude	124,600	96	455 455	150 175	605 630	37 37	33 35	70 72				82-86

	Input fuel (tons/day)	Thermal efficiency (per cent)	Total capital[6] ($ millions)	Annual operating cost ($ millions)	Costs (cents per million B.t.u. of product), 330 days/year operation			
					Capital, at 15%/year	Operating costs	Coal or oil shale cost	Total cost
Coal gasification								
Lurgi—bituminous[1]	14,700-17,900	56-68	334-390	21.4-22.2	60.7-70.9	25.9-26.9	47.1-54.1	135-150
Lurgi—Western[2]	19,600-23,600	56-66	290-390	19.5-23.0	52.7-70.9	23.6-26.5	23.6-26.5	100-127
Coal liquefaction	13,200-17,500	60-75	233-373	22-35	43.4-67.6	26.7-35.0	42.7-56.0	112-166
Low-B.t.u. gas								
Bituminous[1]	12,500-14,300	70-80	195-206		35.5-37.6		40-45.7	110-125
Western[2]	16,700-19,000	70-80	195-206		35.5-37.6		20-22.7	90-105
Methanol—bituminous[1]	14,900	60-87	279-364	44	50.7-66.2	54	53.4	158-174
Oil shale								
Gasification[4]	94,500	74	415		53.2	25.0	56.1	134.3
Liquefaction[3]	72,900	96	342-350		45.0	27.0	42.6-48.2	114.8-120.6
Liquefaction[4]	52,000	96	276-327		37.6	23.4	46.8-52.6	107.8-113.6

Table A.2: Plant Costs for 250 $\times$ 10^9 B.t.u. per day of Various Synthetic Fuels. In this table, the figures shown in Table A.1 are made comparable by recalculations described in the text of the Appendix. Footnotes to the table:

[1] Thirty-two cents per million B.t.u., 25 million B.t.u. per ton, $8.00 per ton.

[2] Sixteen cents per million B.t.u., 18.75 million B.t.u. per ton, $3.00 per ton.

[3] Twenty-five gallons of oil per ton of shale.

[4] Thirty-five gallons of oil per ton of shale.

[5] Labor at $5.50 per hour, 2.5 per cent for taxes and insurance on plant investment, 4.5 per cent for maintenance.

[6] Includes onsites, offsites, auxiliaries, five per cent start-ups, 15 per cent interest during construction, and 7.5 per cent working capital. The plant costs are normalized to 250 $\times$ 10^9 B.t.u. per day of product by assuming these costs to vary with capacity to the 0.9 power.

EXCERPTS FROM CHAPTER II, "DOMESTIC ENERGY SUPPLY SUMMARY," *PROJECT INDEPENDENCE REPORT*, FEDERAL ENERGY ADMINISTRATION, 1974

CHAPTER II

DOMESTIC ENERGY SUPPLY
SUMMARY

To assess the domestic energy situation between now and 1985, we have to analyze the effects of existing policies upon future supplies and identify alternative actions to increase domestic production. FEA's evaluation of the cost and levels of potential production was undertaken by nine separate interagency fuel task forces which evaluated:

1. Oil
2. Natural Gas
3. Coal
4. Nuclear
5. Shale Oil
6. Synthetic Fuels
7. Solar
8. Geothermal
9. Facilities

The final reports of these individual task forces are available separately from the Government Printing Office (See Appendix AVII for working group membership and Appendix AVIII for the list of task force reports).

The first section of this chapter summarizes the methods, assumptions, and findings of the supply analysis, and the policy implications of these results. The remainder of the chapter describes each of the energy source analyses in greater detail.

Methodology and Assumptions

The fuel task forces developed estimates of potential production levels for each fuel, as a function of price. These figures were prepared for 1977, 1980, and 1985, taking account of production leadtimes and institutional factors which could affect the rate of growth. Data were compiled for the major producing regions of the country, which are different for each fuel, as well as for the Nation as a whole. Thus, the task forces analyzed nine coal regions, twelve oil and gas regions, and nine electric reliability councils. The regional approach highlights differing production costs, potential recoverable reserves, finding rates, transportation capacities and costs, and provides a basis for analysis of environmental impacts and production constraints.

Energy production is largely determined by an array of Government policies and by economic conditions. The fuel task forces evaluated potential production under a Business As Usual (BAU) case and Accelerated Development (AD) case. The Business As Usual strategy assumes, to the extent possible, a continuation of existing policies and no new actions to stimulate supply or to remove barriers that limit production. It assumes there will be no changes in current tax policies; phasing out of current price and allocation programs during 1975; implementation of current environmental regulations; and continuation of the $11 billion energy research and development program. The Accelerated Development strategy assumed the implementation of incentives or other programs to stimulate supply and the relaxation of selected key barriers that inhibit production. It should be noted that many of the options considered under the AD strategy would require Congressional approval.

The major differences between the BAU and AD strategies are with regard to degree of Government intervention, rate of leasing, regulatory controls, and relaxation of institutional barriers. A comparison of major BAU and AD assumptions is shown in Table II-1. More detailed descriptions of assumptions are contained in the Task Force reports.

Table II-1
Comparison of BAU and AD Assumptions

Energy Source	Business As Usual Assumptions	Accelerated Development Assumptions
Oil	Moderate OCS leasing program (1-3 million acres per year); Prudhoe Bay developed with one pipeline	Accelerated OCS leasing program, including Atlantic and Gulf of Alaska; expanded Alaskan program assuming additional pipeline and authority to develop Naval Petroleum Reserve No. 4
Natural Gas	Phased deregulation of new natural gas; LNG facilities in Alaska	Deregulation of new natural gas; additional gas pipelines in Alaska; gas produced in tight formations
Coal	Some Federal coal land leasing; phased implementation of Clean Air Act with installation of effective stack gas control equipment; moderate strip mining legislation	Same as BAU with additional leasing and larger new mines
Nuclear	No change in licensing or regulations; added enrichment and reprocessing capability	Streamlined siting and licensing to reduce leadtimes; increased reliability; additional uranium availability; material allocation

Table II-1
Comparison of BAU and AD Assumptions
(Continued)

Energy Source	Business As Usual Assumptions	Accelerated Development Assumptions
Synthetic Fuels	No change from current policies	Streamlined licensing and siting; financial incentives; increased water availability
Shale Oil	No change from existing policies	Additional leasing of Federal lands; modification of Colorado air quality standards; financial incentives; increased water availability
Geothermal	Continued R&D and Federal leasing programs	Leasing of Federal lands; streamlined licensing and regulatory procedures; financial incentives
Solar	Continued R&D program	Additional R&D expenditures and financial incentives

Reserves

The United States has abundant coal reserves. At current levels of usage, our coal reserves could last about 800 years, well beyond the availability of other fossil fuels (see Table II-2 for a comparison of reserves for different fuels). Although about 90 percent of the strip mineable coal can be recovered, only about half of the underground coal reserves can be recovered with current mining technology. Coal production has traditionally been concentrated in Appalachia, but most of the Nation's reserves are in the Midwest and Northern Great Plains.

Oil and gas reserves are considerably more limited. Even with extensions, revision, and discovery of new pools in known fields, proven reserves are less than 46 billion barrels, or less than 10 years of domestic supply (includes Prudhoe Bay, but not Naval Petroleum Reserve No. 4). The greatest potential for new discoveries lies in the offshore areas (OCS) and in Alaska. Many of the areas of greatest promise are publicly owned and to date have not been explored. For example, of the 70,000 square miles on the North Slope of Alaska that are potentially favorably-producing areas all but 27,000 square miles are reserved in the Arctic National Wildlife Range and Naval Petroleum Reserve No. 4 (NPR-4). Natural gas reserves are even more concentrated in Alaska, which has about one-third of the Nation's gas potential. The high oil and gas potential in these largely unexplored areas underscores the uncertainty of future levels of production.

In addition to the oil in conventional fields, there are a large number of shallow oil fields containing oil-saturated sand reserviors; deposits, primarily in Utah, of oil-impregnated rocks, known as tar sands; shale oil; and heavy crude oil reserves, mainly in California. The ability to produce oil from these areas is heavily dependent upon the price of world oil and the environmental concerns of local residents.

Table II-2
Proven Reserves

Source	Fuel Units	Quadrillion Btu's	Years Left at 1972 Consumption Levels
Coal			
high sulfur (more than 1%)	273 billion tons	6908	
low sulfur (less than 1%)	160 billion tons	3838	
TOTAL	433 billion tons	10746	823
Oil			
lower 48 (crude)	30 billion barrels	176	
natural gas liquids	6 billion barrels	37	
Alaska	10 billion barrels	59	
TOTAL	46 billion barrels	272	8
Gas			
lower 48	218 TCF	225	
Alaska	32 TCF	32	
TOTAL		257	11
Shale	20-170 billion barrels	116-986	3-28
Tar Sands	29 billion barrels	168	28

Major Findings

Actual production levels will be affected by demand for various fuels; interfuel substitution; the price of world oil and access to imports; availability of materials, equipment, water, capital, manpower, and transportation; and Government actions. The fuel task forces assumed there were no constraints to production and did not take account of expected demand. These potential levels of production are combined with the FEA demand forecast and transportation cost estimates to develop a least cost way of producing and delivering energy to demand centers. The analytical approach followed is described in Chapter VIII.

Under the Business As Usual strategy, and if world oil is $11 a barrel. oil production could increase to 15 million barrels per day (MMBD). Under Accelerated Development at $11 oil, production could increase to 20 MMBD The AD case assumes large-scale development in NPR-4; the Atlantic, Alaskan, and Pacific OCS; and a more extensive leasing program. Although the potential exists for 20 MMBD production, actual production levels will probably be lower. There is considerable uncertainty regarding NPR-4, Alaska, and the Atlantic OCS, and it is unlikely that all institutional and equipment barriers could be overcome.

The potential for coal development is virtually unlimited under accelerated conditions if no equipment, manpower, or demand constraints are assumed. Coal production could be over 2 billion tons per year in 1985 under these assumptions, although demand limitations are likely to keep production to about 1 billion tons in 1985. Natural gas production can be increased through increasing availability. Synthetic fuels, geothermal, solar, and shale oil levels are considerably higher under AD, although still relatively small contributors to total energy production before 1985. Nuclear power also shows large increases under AD as regulatory delays are reduced through streamlined siting and licensing practices. (See Table II-3 for BAU and AD production levels.)

Table II-3
Maximum 1985 Production Levels Under BAU and AD
(at $11 Oil)

Source	BAU Potential	AD Potential
Oil	15.0 million barrels/day	20.0 million barrels/day
Natural Gas	23.4 trillion cubic feet/year	29.3 trillion cubic feet/year
Coal	1.1 billion tons/year	2.1 billion tons/year
Nuclear	234 million kilowatts	275 million kilowatts
Coal Gasification	0.5 trillion cubic feet/year	1.0 trillion cubic feet/year
Coal Liquefaction	-0-	500,000 barrels/day
Shale Oil	250,000 barrels/day	1.0 million barrels/day
Geothermal	6000 megawatts	15,000 megawatts
Solar Heating & Cooling	0.3 quadrillion Btu's	0.6 quadrillion Btu's
Solar Electricity	41 million MWh/yr	151 million MWh/yr

The variation in world oil price has a significant effect on potential production levels of source energy sources. Obviously, oil is very sensitive to imported prices. Production under AD conditions could be 20 MMBD in 1985 at $11 oil, but would be 16.9 MMBD at $7 oil. The major reason for these differences is that some sources that are economic at the higher prices are not economic when $7 a barrel imports are available. These sources, such as secondary and tertiary recovery, some Alaskan oil, and some heavy crude oil are produced at greater rates in the AD case. At $4 oil, domestic production would decline considerably, as most of the Alaskan production would not be economic.

The variation of world oil prices has virtually no effect on the supply of coal. The supply curve for coal is basically inelastic in the $7-11 oil price range. In the long term, after any immediate constraints have been relieved, coal can be produced in greater quantities than it can be consumed. The supply of nuclear power is relatively inelastic between $7 and $11 oil, as its availability depends more upon capital requirements, regulatory and delivery delays, perceptions about safety, and electricity demand, than on the price of oil. Nuclear power has the cheapest life cycle cost for base load electric lower generation and, along with coal, could substitute for some petroleum demand. Natural gas is generally cheaper to produce and transport than oil and is less sensitive to varying oil prices.

Considerations for Policy Development

The Accelerated Supply Case reflects substantial increases in the rate of production of several energy sources by 1985, including nuclear power and oil from Alaska and the Outer Continental Shelf. The increases are premised on Government action (Federal, state and local) and industry initiatives that are unlikely to take place unless a number of policy problems can be solved, most of which involve reforms in the regulatory process or the reconcilation of conflicting economic, environmental and social interests. This portion of the chapter highlights several of the most important policy problems.

Energy Facilities. A pervasive problem affecting attainment of the supply increases in the Accelerated Supply Case is the complexity and inconsistency of siting, licensing and regulatory procedures. Leadtimes for new facilities have increased beyond the normal engineering and construction delays. It takes eight or nine years to start up a nuclear plant from the time the decision is made to build the plant (See Table II-4 for estimates of current leadtimes.)

Table II-4
Estimated Facility Leadtimes
(Years from Decision to Start Up)

Type of Facility	Years Leadtime
Nuclear Electric Plants	8-9
Coal Electric Plants	5
Oil Electric Plants	5
Synthetic Plants	
Low Btu Gas	5
Pipeline Gas	5
Liquification	5
Shale Oil Plants	6
New Mines	
Surface	
Private Lands	3
Federal Lands	5
Underground	
Private Lands	5
Federal Lands	5-6
New OCS Oil Fields	2-4
New Onshore Oil Fields	1-3
Geothermal Electric	5
Hydroelectric	20

There are several factors contributing to long leadtimes, including local and State land use siting reviews; Atomic Energy Commission approval of the construction and operation of nuclear power plants; Federal Power Commission approval of interstate gas pipelines; the timely availability of land by the Department of the Interior; and the review and approval of environmental impact statements. While each of these functions is necessary, the procedures add 1-5 years to the lag in bringing a new power source to the consumer. Additional delays may be caused by lack of coordination between Federal, State and local regulatory agencies; and the trend toward larger energy facilities may require special regional siting considerations and increased standardization.

More than forty Federal agencies, bureaus and commissions have a role in energy. In addition, State and local government agencies are involved in the evaluation of proposed energy sites and facilities, and for many planned facilities there is no method to resolve siting conflicts. The regulatory framework often appears fragmented and directionless. There are no mechanisms to insure that decisions made are consistent with national requirements for energy and that these needs are balanced with other objectives, such as environmental quality and considerations of social disruptions at the regional level. Federal energy regulatory agencies have sometimes adopted narrow decisionmaking perspectives ignoring the overall impact of their actions. Also, the regulatory structure and its legislative mandate have not always encouraged expeditious agency responses to changes in technology, the economy, or international relations. This is exemplified by regulations on natural gas and old oil.

Local resistance to energy projects is growing. Planning projects to be located in sparsely populated areas does not necessarily reduce the resistance Municipal services such as schools, hospitals, fire, housing, sewage and water supply in many rural areas are not sufficient to support a rapid increas in demand. The environmental, social and economic impact of intensive population growth (to mine coal, mine and mill shale, drill for oil, etc.) are likely to create chaotic growth. The prospect of boom and bust economics and its disruption of local life will continue to be resisted by local Government officials and citizens.

New facilities such as deepwater ports and floating nuclear powerplants, as well as liquified natural gas plants are also generating public opposition and delays are commonplace.

To attain the accelerated supply levels for each fuel, and to meet even the less ambitious production rates of the base case, the institutional bottlenecks will need to be overcome and project decisions reached much more quickly. Our estimates under the base case alone imply the addition of 15 new refineries and hundreds of new powerplants (See Table II-5). The number of coal-fired plants is less in the accelerated case since more nuclear and geothermal power and less expensive oil become available for electric generation. The present regulatory framework and the financial problems of utilities may reduce the number of new plants constructed.

Table II-5
Selected Additional Facilities Required by 1985 Under the Base Case and Accelerated Supply Scenarios

Type Facility	Base Case Projected Capacity	Base Case New Facilities Required	Accelerated Supply Projected Capacity	Accelerated Supply New Facilities Required
Refineries*	16.6 MBD	15	16.6 MBD	15
Electric Generating				
-Nuclear**	204,000 MW	183	240,000 MW	219
-Coal***1/	366,000 MW	365	307,000 MW	255
-Combustion**** (Gas Turbine combined cycle, etc.)	189,000 MW	312	186,000 MW	306

*Typical Facility 200,000 barrels per day
**Typical Facility 1000 MW
***Typical Facility 800 MW
****Typical Facility 500 MW

1/ Assumes retirement and replacement of existing facilities at a rate of three percent a year of existing capacity.

Alaska: Assuming the validity of current reserves estimates and a continued or increased pace of geophysical exploration, Alaska will be a sizeable source of both oil and natural gas by 1985 under the BAU case and especially under the Accelerated Supply Case. Under accelerated supply conditions, for example, production could be as high as 5.3 million barrels per day for oil and 5.3 trillion cubic feet per year for gas. Were this production to be attained, Alaska would account for about one-fourth of all U.S. oil and gas production by 1985 (See Table II-6 for oil production figures).

Table II-6
Potential Alaskan Oil Production in 1985
(Millions of Barrels Per Day)

Alaskan Region	1974 Production	1985 Base Case	1985 Accelerated Supply
North Slope - Prudhoe Bay	0	2.5	2.5
NPR-4	0	0	2.0
South Alaska	0.2	0.5	0.8
TOTAL	0.2	3.0	5.3

The implications of these production possibilities are immense. Developing oil and gas production to these levels would likely require another 48-inch oil pipeline; two gas pipelines; and depending on the routes chosen, sizeable numbers of tankers. Both Trans-Alaska and Mackenzie Valley pipeline routes may well be used. Moreover, the development of the Alaskan OCS area would require additional transportation facilites. Certain processing facilities could be required for both the North Slope and the OCS: at a minimum, some gas processing and additional LNG facilities would be needed. Moreover, a heavy investment in supplier and infrastructure facilities, primarily internal transportation, would be required to support these energy industry investments. This development of Alaskan resources would, however, have to take full account of environmental considerations.

Some risk of damage to the human and natural environment is an inseparable part of almost any energy development activity. In Alaska, these risks are especially high. Most of Alaska is a pristine wilderness characterized by permafrost, fragile terrain, very low temperatures, severe winter weather, and is subject to earthquakes. Offshore and onshore development, especially transportation, involve greater risks than those encountered in most other oil and gas producing areas. Economic development of Alaska's petroleum and other mineral resources will change the face and way of life in Alaska, even if it were undertaken in an environmentally sound manner. for example, roads to service pipelines will open up vast areas of Alaskan wilderness to hunters, fishermen, and other recreational developments.

The problem in the context of Project Independence is how to develop the vast oil and gas supplies in Alaska and their required processing and transportation facilities in a timely and environmentally acceptable manner. The Federal Government has an immediate and major responsibility for addressing this problem, not only because of the size of the contribution Alaskan resources can make toward increased self-sufficiency by 1985, but because of the Federal Government's land management obligation, its control of NPR-4, its regulatory function, and its special relationship with the Alaskan native population.

Emerging Technologies: The emerging energy technologies (shale oil, synthetic fuels from coal, geothermal and solar power) will not have a major input to the Nation's energy resources until at least the 1985-1990 time period. This finding takes into account the current status of these energy technologies; their need for additional engineering development; economics; and the leadtime involved once engineering development is completed, before major energy production levels can be obtained. The extent that these emerging technologies will be viable sources of energy beyond the Project Independence timeframe will largely depend on the advances that will be made in the next 5-7 years, the prices of competing fuels, and the commitment to their long-range use.

Outer Continental Shelf (OCS): The Outer Continental Shelf is a major source of oil that will keep domestic production from rapid decline and reduce our dependence on foreign oil. The OCS could produce 3.1 MMBD and 5.1 MMBD at $11 prices in the Base and Accelerated Supply Cases, respectively, in 1985 (See Table II-7).

Table II-7
Potential OCS Oil Production at $11 Imported Oil
(Millions of Barrels/Day)

	1973 Actual	1985 BAU	1985 AD
Alaska, OCS	0.2	0.5	0.8
Pacific (Excl Alaska)	0.1	0.5	1.3
Atlantic	0	0	0.5
Gulf of Mexico	1.3	2.1	2.5
TOTAL	1.6	3.1	5.1

These projected production increases will depend on the rate, location and timing of new leasing. The OCS is owned by the public. It cannot be developed by industry unless it is made available through Government leasing The Federal Government began leasing in 1954 and has so far leased about 10 million acres in over 2,200 tracts. Nearly 90 percent of the acres leased have been in the Gulf of Mexico.

There are large areas of the OCS--off the Pacific coast, off Alaska, and off the Atlantic coast--that are not presently leased that may be worthwhile for exploration and drilling. However, before Federal decisions can be made on the rate, location and timing of additional leasing, at least three concerns must be resolved:

1. The environmental risks of exploration and development.

2. Protection of coastal State interests.

3. Protection of fair market return to the public.

The Coastal States are concerned with the environmental, social and economic effects of OCS development. There will be certain adverse environmental effects associated with OCS drilling and production. These effects will vary by area. For example, development in areas with extreme weather and seismic conditions, such as Alaska, have much greater risks of environmental damage than other areas, and production may be precluded or seriously limited. The onshore effects of OCS development may be particularly significant. An infrastructure of maintenance facilities, refineries, petrochemical plants, construction, and supporting services may result from nearby OCS production.

Since production potential in frontier areas is highly uncertain until drilling actually occurs and since environmental baseline studies may be needed before development begins, a policy of large-scale exploration of the OCS may be desirable.

It is possible that accelerated leasing, while it will raise total bonuses, will reduce the average bonus bid per acre. On the other hand, accelerated leasing should mean that more tracts receive few bids and lower bids per tract, and hence there is a threat to the leasing goal of a return of fair value to the public. This threat can be reduced by taking steps to maintain competition in the lease sale. Specific steps to stimulate competitive bidding could include a ban on joint bidding amonq major producers, more rapid disclosure of geological and geophysical information and the maintenance of a stringent system of determining minimum bids below which the lease will not be issued.

Natural Gas Deregulation. Another difficult institutional issue is the regulation of natural gas prices at the wellhead. Since 1960, the FPC has used the "area pricing" concept for setting procedures' rates. Ceiling prices are established in each of the major gas producing areas for gas sold in interstate commerce. In determining area rates the FPC has used the historical, utility type cost-of-service approach.

These regulatory standards have provided incentives to producers, faced with rising costs, to seek other investments. Gas wells drilled in the United States declined from 5,262 in 1960 to 3,679 in 1971. This has contributed to a steady decline in the availability of new gas supplies and reserve additions. Artifically low prices for natural gas have resulted in excess demand and reduced supply, causing a serious gas shortage. Most pipelines and distributors have curtailed gas service.

The prospect for increased natural gas supplies is not encouraging. If the current field price of natural gas for interstate use is maintained, the total wellhead production in 1985 should decline by over six trillion cubic feet per year from 1974 levels (a decline of almost 30 percent). In addition, the share of total gas used in interstate markets could decline from 60 percent to 40 percent. At the other extreme, if natural gas prices are deregulated, production would rise from 1974 levels and be almost 50 percent higher in 1985 than the regulated case. While the effects of price regulation does not impact associated dissolved gas, it has major impacts on non-associated gas. Synthetic pipeline gas from coal will cost about $2.00 per thousand cubic feet and would not be economic if sufficient supplies of natural gas were available at deregulated prices.

CRUDE OIL

Background

The first commercial well in the United States was drilled at Titusville, Pennsylvania, in 1859. For the next 30 years the United States was virtually the world's only source of crude oil and refined products - the principal product being illuminating oil. By the turn of the century, United States oil production increased to nearly 60 million barrels annually.

By World War I, oil production had expanded into 16 states. Drilling and refining technology developed rapidly and many companies emerged in this period, as competition was aided by court actions to dissolve the Standard Oil trust. In the years between the World Wars, oil's growth continued, enhanced by expanding requirements for gasoline, and was interrupted only by the depression.

Fears of "running out of oil" were expressed in the early 1920's, and American companies were urged by the Government to develop oil production abroad to augment domestic supplies. These circumstances were reversed within a decade. When depression-limited demand coincided with the development of the east Texas field in 1930 and other large fields soon after, the problem became one of management of surplus oil production. As a result of these circumstances oil production was concentrated in large, vertically integrated companies, and States became regulators and conservers of crude oil production. State regulatory agencies began to control well spacing, to restrict production to maximum efficient rates to prevent reservoir damage, and to prorate well production on the basis of market demand.

At the close of World War II, capacity was barely sufficient to meet market demand. By the mid-1950's, spurred by strong demand and rising prices, these lags had been overcome. Both oil reserves and the capacity to produce oil far exceeded needs, and drilling activity began a decline that lasted a decade and a half. As a consequence, the rate of reserve additions slowed; and 10 years later new annual additions to both oil and gas reserves became insufficient to replace production, and production began to decline.

Production peaked in 1970, reserves have fallen each year since 1966, and drilling effort has only recently reversed its long-term downward trend. Only the discovery of the Prudhoe Bay field in the Alaskan North Slope was a major exception to this trend.

With foreign oil available at costs far below those of domestic production, the major international oil companies greatly expanded production in foreign areas. Concerned over the national security aspects of rising imports and a deteriorating domestic industry, the Federal Government encouraged voluntary import restrictions under 1955 and 1957 programs. When these did not stem the rising tide of imports, President Eisenhower, in 1959, invoked the national security provision of the Trade Agreement Extension Act to establish mandatory oil import quotas.

Although this import quota program provided the domestic petroleum industry a measure of price protection from foreign competition, other policies and market demand prorationing limited the capacity that was used. Indeed, the United States was dependent on foreign sources for 19 percent of its oil supplies in 1959; by 1970, this dependence had grown to 26 percent. Consumption of petroleum rose from 6.5 million barrels per day in 1950 to 14.7 million barrels per day in 1970, an average compounded growth rate of 4.2 percent (see Figures II-1 and II-2 for trends in petroleum consumption). A large part of the increased imports (more than 40 percent) was in residual fuel oil, which was effectively decontrolled in 1966.

As the domestic oil-producing industry approached capacity operations, periodic modifications were made in the import quota levels in order to provide enough oil to meet domestic needs. On April 18, 1973, the President suspended the mandatory oil-import control program, replacing it with a system of license fees that escalate over time. The license fee program is designed to support the long-term restoration of domestic capacity, particularly in refining, while providing for the near-term need for access to imported oil supplies.

In 1969, a major oil spill in the Santa Barbara Channel and another on the Gulf Coast directed attention to the environmental risks of offshore production. As a result, the Department of the Interior suspended the leasing of OCS acreage, pending development of operating procedures and regulations to minimize the potential for future significant environmental damage. The delays in OCS leasing have affected oil production, as about one-third of the recoverable oil remains to be discovered, and many of the most favorable prospects for oil and gas production are believed to exist in the Federally controlled OCS. A 10 million acre leasing program is now planned for 1975.

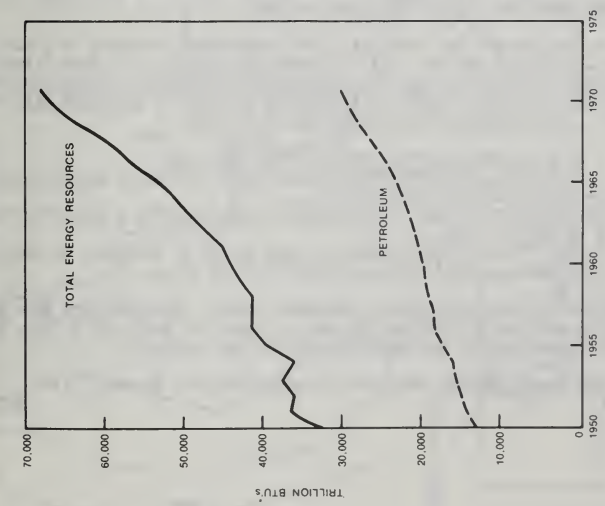
Methodology and Assumptions

Future supplies of oil will be determined by four fundamental factors:

- The amount of oil resources remaining to be found.
- Our success in finding the remaining supply.
- Our ability to recover (produce) what is found.
- The costs of the necessary exploration and production efforts.

Figure II-1

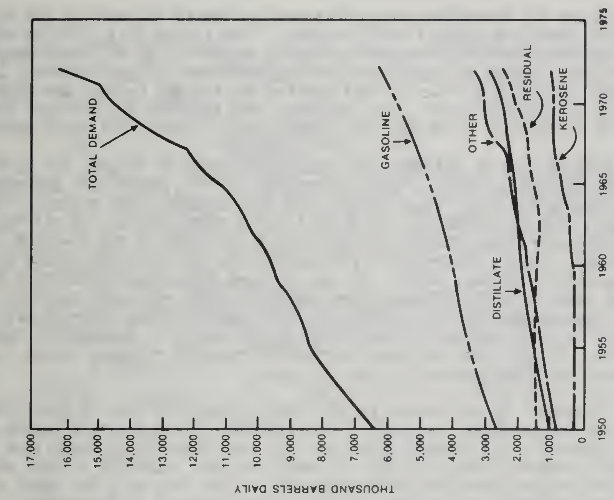
U.S. GROSS CONSUMPTION OF ENERGY RESOURCES



Source BUREAU OF MINES

Figure II-2

DOMESTIC DEMAND FOR PETROLEUM



SOURCE. BUREAU OF MINES

64-282 O - 76 - 11

Future oil production and prices were estimated for each of the 12 National Petroleum Council (NPC) regions. (See Figure II-3). The model used for these calculations was an updated version of an NPC model developed to produce a report on production for the Department of the Interior. 1/ A manual procedure similar to that applied for the NPC regions was used to analyze the Alaskan North Slope (including NPR #4), NPR #1, military reservations in the Gulf of Mexico and California, tar sands, and heavy hydrocarbons.

Methods used to estimate oil supply at a range of prices, for both BAU and AD scenarios, can be briefly summarized. First, optimistic estimates of annual exploratory drilling footage were developed for each region. These footages were multiplied by projected finding rates (barrels of oil found per exploratory foot drilled) to estimate discoveries of oil-in-place. Estimated recovery factors were then applied to calculate the volume of oil recoverable by primary method. It was assumed that annual production from proven reserves would be a constant fraction of the remaining reserves. The total footage required to process and fully develop these reserves was calculated by applying appropriate ratios to the amount of exploratory footage drilled. All of these estimates varied by producing regions, taking into account the unique characteristics of each.

Increments to the proven reserves were added at 5- and 10-year intervals to allow for secondary recovery. The extent of the secondary recovery at each interval was estimated by taking into consideration the magnitude of the primary recovery, along with the ultimate recovery potential in each region. Tertiary recovery was similarly estimated, except that only one phase of tertiary recovery was included in the 15-year interval of projection. For new fields, the first phase of the tertiary recovery was assumed to occur 10 years after the initial discovery of oil.

It was assumed that exploration and development projects in a particular region would be undertaken only if economically viable. Economic viability was determined by using the discounted cash flow method to calculate minimum acceptable prices per barrel of oil needed to attain a specified rate of return. The following major assumptions were used:

- A 10-percent required rate of return was used.
- Cash bonuses and rentals on leases were treated as economic rents and excluded as items of cost.
- Production declines exponentially in accord with a depletion factor or decline rate.
- The life of primary projects is 30 years, of secondary projects is 25 years, and of tertiary projects is 20 years.

Investments, direct and indirect expenses, taxes, and deductions were estimated in relation to drilling footage and number of wells for primary projects, and to production for the secondary and tertiary projects.

1/ U. S. Energy Outlook, National Petroleum Council, December, 1972.

Figure II-3

NPC OIL REGIONS

Source: NPC, FUTURE PETROLEUM PROVINCES OF THE UNITED STATES, A SUMMARY; JULY 1970 - WITH SLIGHT MODIFICATION.

Decisions on the feasibility of secondary projects depended on undertaking a primary project. If the required price per barrel of a secondary project was found to be lower than the required price of its related primary project, primary and secondary were evaluated jointly in calculating their minimum acceptable price. If the required price for secondary was greater than for its primary project, the secondary project was evaluated independently.

To obtain the regional supply estimates for each year and at various minimum acceptable prices, the yearly productions from all the primary, secondary, and tertiary projects found to be economically viable were aggregated.

The principal differences between the BAU and the AD scenarios are the assumptions that were made about Government policies on natural gas price regulation, OCS leasing, and Naval Petroleum Reserves. The BAU case assumed the economic regulation of natural gas prices where the prices are allowed to rise to clear the market. These prices were calculated in the supply-demand balancing analysis and the revenues from associated-dissolved gas were credited to the minimum acceptable price for oil.

Leasing of OCS lands was limited, in the BAU scenario, to levels consistent with the latest published Bureau of Land Management (BLM) schedules. Drilling activity consistent with these leasing levels and with recent regional drilling trends was projected at 63 million exploratory feet for the 1974 to 1988 period. Under the AD scenario, the availability of OCS lands did not limit drilling activity. Under these conditions, drilling was assumed to be limited by the availability of resource and economic extraction rates. Projected oil discoveries were constrained to 75 percent of the ultimate recoverable resources estimated by the NPC for each OCS region. This constraint resulted in a cumulative exploratory drilling assumption of 110 million feet in OCS areas for the 15-year drilling period, other than drilling in military reservations.

Under BAU conditions, royalties on offshore leases were assumed to remain at the existing one-sixth rate. Under the AD scenario, it was assumed that these royalties would be reduced to the statutory minimum of one-eighth.

No development of Federally owned petroleum reserves was assumed under BAU conditions. Under the AD scenario, however, it was assumed that development would occur in Naval Petroleum Reserve #1 (Elk Hills, California), Naval Petroleum Reserve #4 (North Slope, Alaska), and military reservations in the Gulf of Mexico and California OCS.

Advanced technology was assumed to increase substantially in the AD scenario over BAU levels, particularly in relation to enhanced recovery. Under AD conditions, the tertiary recovery factor was increased 33 percent over BAU assumptions. Finally, each scenario assumes that there will be no limitations on the availability of capital, manpower, materials or transportation.

Major Findings

The analysis was focused on developing estimates of production possibilities at various minimum acceptable prices. The following are the major task force findings:

1. Because of the long lead times required to bring new petroleum fields into production, domestic production of crude and natural gas liquids (NGL) will continue to decline for the next few years, regardless of higher prices or policies designed to encourage exploration. At minimum acceptable prices 1/ of $4 a barrel or less, production could continue to decline throughout the forecast period, even with new production from the OCS and Alaska. Even the development of NPR 1 (Elk Hills) and extensive OCS leasing could increase production by only about one million barrels.

Under both BAU and AD assumptions, minimum acceptable prices of $7 or higher would reverse the downward production trend. At $7 and $11 a barrel, respectively, production, under the BAU scenario, would increase to 11.1-12.2 million barrels a day by 1980, and to 11.9-15.0 million barrels a day by 1985, exceeding the all-time high production of 11.3 million barrels a day reached in 1970. (see Table II-8 for crude oil and natural gas liquids estimates):

Table II-8
Summation of Unconstrained Regional Production Possibilities for Crude Oil and Natural Gas Liquids
(Million barrels per day)

Minimum Acceptable Price Per Barrel	1974	1977	1980	1985
Business-As-Usual				
$ 4	10.5	9.0	9.8	9.8
7	10.5	9.5	11.1	11.9
11	10.5	9.9	12.2	15.0
Accelerated Development				
$ 4	10.5	9.7	11.1	11.6
7	10.5	10.2	12.9	16.9
11	10.5	10.3	13.5	20.0

1/ Defined as exploration and production costs plus royalty and 10 percent after tax discounted cash flow from investment, but excluding lease acquisition cost and rental. These rents were evaluated after market clearing prices were determined.

2. At $11 per barrel oil, domestic onshore production would increase slightly under both BAU and AD assumptions. Almost half of the onshore production would be from new secondary and tertiary recovery, while conventional and new primary fields would decline considerably from 1974 levels.

The major new source of oil in these projections is Alaska. Under BAU assumptions, Alaska would provide 3 million barrels per day, mainly from the North Slope fields. If development of the Naval Petroleum Reserves is allowed, an additional 2 million barrels per day could be produced. The increased development in Alaska will shift the focus of United States oil production: Alaska could produce 20-25 percent of our oil by 1985, although it now accounts for less than 2 percent.

The 1985 projections also indicate substantial increases in lower 48 OCS production. Although production could increase about 1.2 million barrels per day under BAU assumptions (two-thirds of the increase from the Gu of Mexico), OCS production could reach 4.3 million barrels per day (300 percent increase) under AD conditions. The major sources of this increase would be the offshore California and Atlantic fields. Considerable opposition to leasing in these areas could be expected (See Table II-9 for a detailed description of potential production levels).

3. If production increases to 15-20 million barrels per day by 1985, this level of production could not be maintained indefinitely at these prices, as oil reserves at these prices would soon peak. Thus, in addition to potential constraints toward achieving these levels of production, the non-renewable nature of these resources should be considered.

4. At a minimum acceptable price of $7 a barrel, under the BAU scenario, almost 40 billion barrels of petroleum liquids would be produced from 1974 to 1985. This is almost equal to the 48 billion barrels of proved and indicated additional reserves of oil and natural gas liquids reported at the end of 1973 by the American Petroleum Institute. However, under AD conditions and at a price of $11 a barrel, cumulative production between 1974 and 1985 would be over 50 billion barrels. These production figures imply that huge additions to reserves would be needed in this time period. These additional reserves would about equal the most conservative estimates of undiscovered recoverable oil in the United States, although they would still be less than NPC estimates.

The uncertainties inherent in estimating future petroleum production (especially uncertainties having to do with the magnitude of undiscovered resources in as yet totally unexplored provinces and the finding rate per foot of exploratory drilling) are so great that numerical estimates of this type are highly speculative.

Table II-9
Potential Rates of Domestic Oil Production
(Millions of barrels per day, at $11 oil)

Production Area	1974	BAU 1985	AD 1985
1. Onshore - Lower 48 States	8.9	9.1	9.9
° Conventional fields and new primary fields	6.9	3.4	3.5
° New secondary	---	2.4	2.4
° New tertiary	---	1.8	2.3
° Natural gas liquids	2.0	1.5	1.6
° Naval Petroleum Reserve #1	---	---	0.2
2. Alaska	0.2	3.0	5.3
° North Slope	---	2.5	2.5
° Southern Alaska (including OCS)	0.2	0.5	0.8
° Naval Petroleum Reserve #4	---	---	2.0
3. Lower 48 Outer Continental Shelf	1.4	2.6	4.3
° Gulf of Mexico	1.3	2.1	2.5
° California OCS	0.1	0.5	1.3
° Atlantic OCS	---	---	0.5
4. Heavy Crude Oil and Tar Sands	---	0.3	0.5
Total Potential Production	10.5	15.0	20.0

Sensitivity analyses show that, within a range of reasonable assumptions, different values regarding discount rates, financial costs, and finding rates could affect the quantities produced at $4, $7 and $11 per barrel in 1985 by 10 to 40 percent. Other assumptions about drilling costs, effective depletion rates, and co-product prices would affect production levels at these prices by as much as 15 percent.

Uncertainties regarding many of the factors used in the oil production model will be resolved only as additional exploration is undertaken. This is especially important in areas of high drilling and production costs, such as northern Alaska and deeper parts of the OCS, where even at high prices only giant fields might be economically feasible. Other uncertainties can be reduced through stabilized government policies affecting petroleum exploration and development.

In addition to the difficulties inherent in projecting the amount of future oil discoveries, a number of factors inherent in the model's assumption could lead to significantly different conclusions on costs and production levels, including:

1. Competition for available labor, material, and capital. Although the availability of labor, material, and capital has been assumed, oil must compete with other energy projects and with the production of non-energy goods and services for these resources. The analysis of resource constraints is discussed in Chapter V.

2. Technology. The projected levels of crude oil supply will depend on utilization of secondary and tertiary recovery. Much of the technology needed to achieve those production levels has not been applied commercially, though its principles are generally known. Depending on the technological success of oil recovery, different production rates and costs could result. These technological successes may require government support, responsiveness of private sector research to higher oil prices, and engineering achievements.

3. Access to resources. The Federal Government controls perhaps 40 percent of the remaining producible oil. The Government makes this acreage available for exploration and development with consideration of environmental and jurisdictional questions. The terms under which Government lands are made available affect the availability of capital, the rate at which lease areas are explored and produced, and the percent of oil-in-place ultimately recovered. State regulations, such as those relating to utilization and well spacing, may also influence production rates, recoveries, and costs.

4. Government price and fiscal policies. Government pricing and fiscal policies also affect production levels. Depletion allowances, tax rates, and fiscal uncertainty could constrain investments.

5. Environmental considerations. All extraction, manufacturing, and distribution processes affect the quality of the environment. The production of oil is no exception; any production level involves some direct and indirect environmental change. Oil spills can affect the marine environment and create aesthetic problems. The development of petroleum production also has social and economic implications, expecially in frontier areas. The Alaskan North Slope, with its fragile ecology and unpopulated areas, presents a particular set of problems. Its abundance of resources suggests that an extraordinary effort is needed to minimize environmental impact. The environmental aspects of oil development are discussed in greater detail in Chapter IV.

NATURAL GAS

NATURAL GAS

Natural gas is primarily methane, the most basic hydrocarbon. It is often found associated with oil in the same geologic formations, but is also found in geologic structures by itself. Its primary use is as a clean-burning fuel, but it is also used as a petrochemical feedstock.

Background

The first natural gas well was put into production in 1821 in Fredonia, New York. The discovery of oil in the U.S. in 1859 began a search that resulted in the discovery of large quantities of natural gas as well a supply for which there was no ready market at the time. Thus, the gas was flared as a part of the process of extracting oil from the ground. But once the possible uses and advantages of natural gas were discovered, it quickly replaced manufactured gas.

The first large-scale use of natural gas was in the manufacture of steel and glass in plants located in Pittsburgh. Initially, the use of gas was confined to areas near gas or oil fields, but the development of long-distance gas transmission systems in the 1930's broadened its market. During World War II, the war effort slowed down growth of gas pipeline and distribution systems. After the war, however, the availability of abundant supplies of natural gas--most of it found in the search for oil--and improved quality of pipe for high-pressure, long-distance delivery enabled the gas utility industry to expand rapidly and widely. Marketed gas production increased from four trillion cubic feet (TCF), in 1946, to eight TCF by 1952, and continued to grow at a 6.5 percent average annual rate in the 1950's and 1960's.

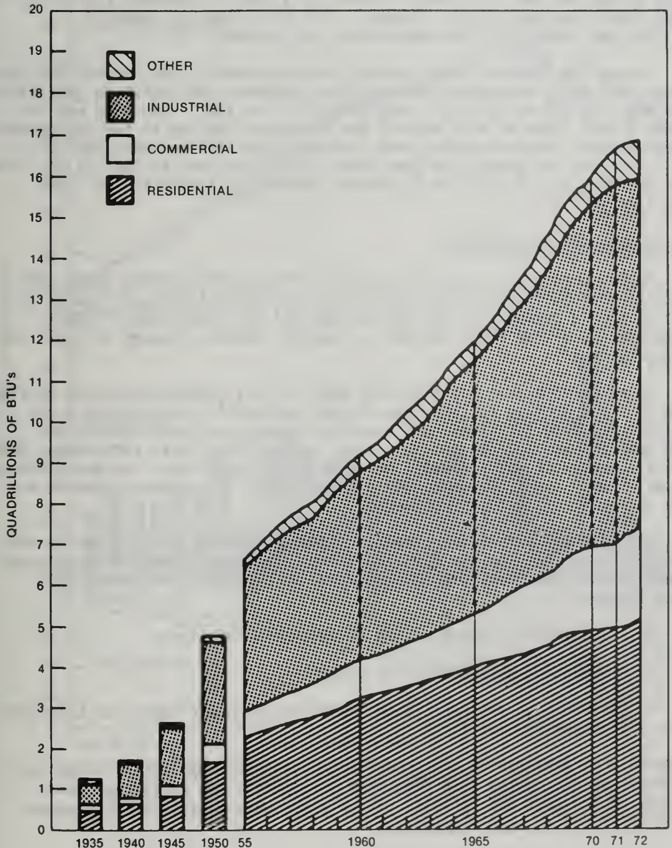
Natural gas now represents about one-third of the total energy consumed by the Nation and almost one-half of the non-transportation uses--an amount twice that supplied by either oil or coal. One-half of the gas is used for residential and commercial purposes, one-sixth for the generation of electricity. and one-third for industrial uses (See Figure II-4 for natural gas utility sales trends).

In the 1970's, the demand for gas has exceeded its supply. Many gas distribution companies have found it necessary to deny gas service to new customers and to enforce contracts for interruptible gas sales. Additionally, the Federal Power Commission has set priorities on gas use.

The Natural Gas Act of 1938 gave the Federal Power Commission authority to regulate interstate pipelines and natural gas imports and exports. In 1954, in the landmark Phillips Petroleum case, the U.S. Supreme Court held that a firm which produces and gathers gas and sells it to a pipeline company is a natural gas company. As a result, the FPC began regulating the wellhead prices at which gas was sold in interstate commerce.

Figure II-4

GAS UTILITY INDUSTRY SALES BY CLASS OF SERVICE



SOURCE: GAS FACTS

REFERENCE: TABLE 5

The approach for establishing producer's prices is based primarily on historical average industry costs. Drilling and exploration costs, on the one hand, have increased considerably in recent years; the cost per foot of a gas well increased 57 percent between 1961 and 1971. But the average price of gas, on the other hand, rose by only about 20 percent (Table II-10 shows production and pricing trends). This price lag has impacted drilling and resulted in the erosion of gas reserves.

Proved gas reserves, the current estimated quantity of natural gas that can be reasonably recovered under existing economic and operating conditions, grew from 147 TCF in 1945 to a peak of 293 TCF in 1967. Since we are consuming 2 to 3 times as much natural gas as we are finding in the continental United States, proved reserves have declined from 1967,and were 250 TCF in 1973. Natural gas production grew from 4.8 TCF per year in 1945 to 22.7 TCF per year in 1971, but has now leveled off at between 22 and 23 TCF per year (See Figure II-5).

Methodology and Assumptions

Future production possibilities and corresponding minimum acceptable prices1/ were estimated for non-associated gas and natural gas liquids in each of the 12 regions defined by the National Petroleum Council (NPC). An adaptation of the NPC's natural gas supply computer program was utilized in the analysis.

There were several modifications made to this program,including development of a new section to calculate minimum acceptable price, using a discounted cash flow technique, and extensive updates and revisions to the data base through 1973 to reflect recent trends in critical variables. Some special sources of gas - Alaska, gas from tight formations, and gas occluded in coal seams - were not amenable to inclusion in the computer program and were therefore analyzed independently.

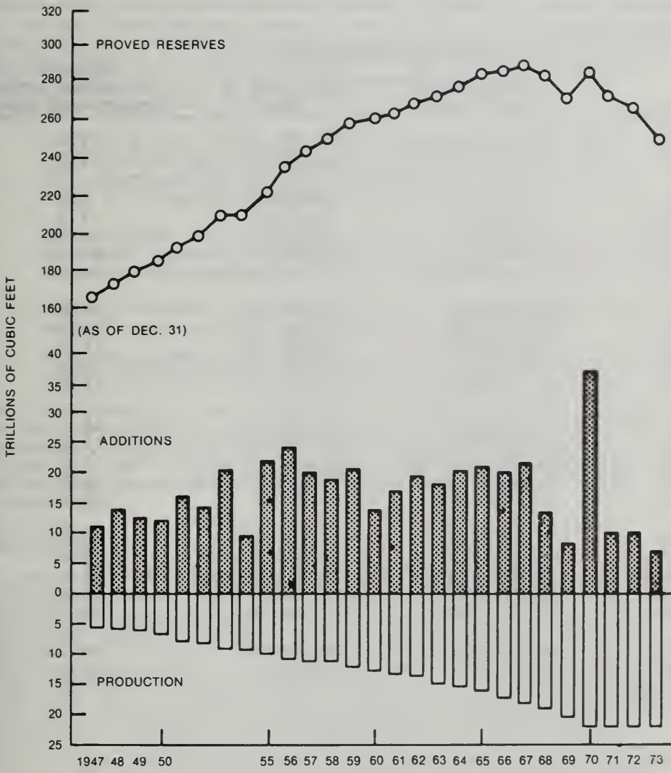
The detailed methodology used to estimate natural gas supplies is very similar to that used by the Oil Task Force. The most important assumptions common to both Business-As-Usual (BAU) and Accelerated Development (AD) scenarios are:

- A 10 percent after-tax rate of return on investment
- A depletion allowance of 22 percent
- Cash bonuses and rentals on leases are economic rents and therefore excluded as cost items

1/ Defined as exploration and production costs plus royalty and 10 percent after-tax discounted cash flow from investment, but excluding lease acquisition cost and rentals. These rents were evaluated after market clearing prices were determined.

Figure II-5

U.S. NATURAL GAS RESERVES



AGA COMMITTEE ON NATURAL GAS RESERVES

Table II-10
Marketed Production of Natural Gas and Average Wellhead Price
1945-1972

YEAR	MARKETED PRODUCTION MILLIONS OF CUBIC FEET	MARKETED PRODUCTION TRILLIONS OF BTU	AVERAGE WELLHEAD PRICE (CENTS PER MCF)
1945	4,049,002	4,481.7	4.9
1950	6,282,660	6,753.0	6.5
1951	7,457,359	8,016.7	7.3
1952	8,013,457	8,614.5	7.8
1953	8,396,916	9,026.7	9.2
1954	8,742,646	9,398.2	10.1
1955	9,405,351	10,110.4	10.4
1956	10,081,923	10,838.2	10.8
1957	10,680,258	11,481.0	11.3
1958	11,030,248	11,857.5	11.9
1959	12,046,115	12,919.5	12.9
1960	12,771,038	13,728.8	14.0
1961	13,254,025	14,248.1	15.1
1962	13,876,622	14,917.4	15.5
1963	14,746,663	15,852.7	15.8
1964	15,462,143	16,621.8	15.4
1965	16,039,753	17,242.7	15.6
1966	17,206,628	18,497.1	15.7
1967	18,171,326	19,534.2	16.0
1968	19,329,600	20,771.0	16.4
1969	20,698,240	22,250.6	16.7
1970	21,920,642	23,564.7	17.1
1971	22,493,017	24,180.0	18.2
1972	22,531,698	24,221.6	18.6

The third assumption is particularly important since it results in a definition of minimum acceptable prices different from that generally used in the industry; nevertheless, the assumption was made to facilitate analysis and provide consistency in comparisons with other energy sources.

The BAU scenario assumes changes in the regulatory environment and projected offshore leasing at levels consistent with current published Bureau of Land Management schedules. In the AD scenario, increased price incentives are assumed, and OCS areas are assumed available in earlier years. These assumptions were reflected in the analysis as follows:

- Drilling activity during the 1975-1978 period will increase at a 5.75 percent average annual rate under BAU conditions, and a 12.2 percent average rate under the AD scenario, although later rates of increase will be less under AD conditions.

- Offshore areas (California, Gulf of Mexico, and Atlantic) will account for roughly 20 percent of drilling activity by the mid-1980's under AD conditions, compared with 15 percent under the BAU scenario.

- Royalty rates were 1/6 offshore and 1/8 onshore under BAU; under AD conditions, they will be the statutory minimum of 1/8.

- Economic regulation of natural gas prices where prices are allowed to rise to clear market, or deregulation on new gas supplies.

Under the AD scenario, it was assumed reserves would be developed from Naval Petroleum Reserve #4 (Alaska) for both non-associated and associated-dissolved gas, along with several minor onshore sources of associated-dissolved gas. R&D activities were assumed to result in recovery of non-associated gas from two minor special sources--tight reservoirs and gas--occluded in coal.

Major Findings

The projections of production possibilities hinge primarily on the projected success of the non-associated gas exploration effort. The major non-associated gas reserve additions are projected to occur Regions 6 and 6A in and around the Gulf of Mexico. These areas will also have fairly low acceptable selling prices. The Atlantic OCS could have large reserve increases by 1985 and could surpass Region 6 after 1985 under accelerated conditions (See Table II-11 for regional additions to reserves). In both the BAU and AD scenarios, total annual findings peak late in the projection period and then begin to decline. This reflects projected drilling in both scenarios, and is indicative of the depletable nature of this resource. Newly found gas will come into production at higher than historical minimum prices as costs increase due to the expansion of exploration and drilling efforts in the face of generally declining findings rates (See Tables II-12 and II-13 for increments, at various minimum price intervals, of non-associated and associated gas, respectively).

Table II-11

SUMMARY OF NON-ASSOCIATED RESERVE ADDITION PROJECTIONS
AND THEIR "MINIMUM ACCEPTABLE PRICES"
LOWER 48 STATES 1/

NPC Region		1974		1977		1980		1985	
		Reserve Additions	"Price"	Reserve Additions	"Price"	Reserve Additions	"Price"	Reserve Additions	"Price"
2	BAU 2/	0.100	$0.60	0.156	$0.6[illegible]	0.213	$0.6	0.278	$0.69
	ACC 3/	0.100	0.60	0.188	0.[illegible]4	0.258	0.66	0.292	0.69
2A	BAU	0.0	--	0.105	0.69	0.129	0.71	0.277	0.80
	ACC	0.0	--	0.253	0.66	0.313	0.68	0.582	0.76
3	BAU	0.349	0.79	0.410	0.78	0.512	0.80	0.722	0.83
	ACC	0.349	0.79	0.494	0.79	0.611	0.80	0.728	0.83
4	BAU	0.407	0.3[illegible]	0.530	0.48	0.621	0.51	0.840	0.58
	ACC	0.407	0.3[illegible]	0.634	0.49	0.725	0.53	0.816	0.59
5	BAU	1.969	0.31	2.144	0.47	2.364	0.58	2.872	0.63
	ACC	1.969	0.31	2.534	0.48	2.772	0.60	2.742	0.67
6	BAU	3.992	0.43	4.245	0.54	4.412	0.61	4.428	0.86
	ACC	3.992	0.43	5.046	0.54	5.103	0.64	4.166	0.91
6A	BAU	3.753	0.29	5.938	0.35	7.195	0.44	6.774	0.71
	ACC	3.753	0.27	7.141	0.34	8.846	0.45	7.368	0.79
7	BAU	1.724	0.47	1.661	0.55	1.858	0.61	2.452	0.69
	ACC	1.724	0.47	1.978	0.56	2.706	0.62	2.424	0.70
8 & 9	BAU	0.049	0.77	0.037	[illegible].04	0.034	1.23	0.036	1.81
	ACC	0.049	0.77	0.045	[illegible].04	0.042	1.23	0.038	1.81
10	BAU	0.716	0.78	0.747	0.70	0.843	0.70	1.117	0.80
	ACC	0.716	0.78	0.901	0.70	0.976	0.73	1.101	0.81
11	BAU	0.0	--	0.003	5.78	0.007	5.60	0.010	5.79
	ACC	0.0	--	0.003	5.78	0.008	5.80	0.010	5.79
11A	BAU	0.0	--	0.0	--	0.064	0.89	1.847	0.92
	ACC	0.0	--	0.0	--	0.627	0.85	3.199	0.88
Sum of Additions:	BAU	13.079		15.976		18.282		21.653	
	ACC	13.059		19.[illegible]17		22.487		23,466	

1/ Volumes in trillions of cubic feet, "prices" in cents per Mcf (constant 1973 dollars).
2/ Business as Usual Scenario.
3/ Accelerated Development Scenario.

TABLE II-12
Total Non-Associated Natural Gas
Production Possibilities
BAU[1/]

Price[2/]	1974	1977	1980	1985
@ 40¢ (or less)	16.522	15.222	13.337	9.483
@ 60¢ (or less)	16.670	15.847	16.028	16.655
@ 80¢ (or less)	16.670	16.073	16.389	18.139
@ $1.00 (or less)	16.670	16.075	16.394	18.152
@ $2.00 (or more)	16.670	16.075	16.400	18.172

AD[1/]

Price	1974	1977	1980	1985
@ $0.40 (or less)	16.552	15.284	13.652	9.100
@ $0.60 (or less)	16.670	16.029	17.781	19.260
@ $0.80 (or less)	16.670	16.265	18.096	21.344
@ $1.00 (or less)	16.670	16.267	18.103	21.348
@ $2.00 (or more)	16.670	16.267	18.110	21.371

1/ ° Production projections are given for the lower 48 states, Alaska and for the natural gas from tight reservoirs.

° Production is given in trillion of cubic feet.

° AD = Accelerated Development

2/ Prices are given in cents per MCF, (in constant 1973 dollars)

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TABLE II-13
Total Associated - Dissolved Natural Gas Production
Possibilities BAU 1/

Minimum Acceptable Oil Price 2/	1974	1977	1980	1985
$ 4.00	3.665	3.167	3.546	3.999
$ 7.00	3.665	3.365	4.003	5.824
$11.00	3.665	3.479	4.328	6.633

AD 1/

Minimum Acceptable Oil Price 2/	1974	1977	1980	1985
$ 4.00	3.665	3.327	3.803	5.190
$ 7.00	3.665	3.533	4.424	6.357
$11.00	3.655	3.539	4.553	7.978

1/ Production projections are given for the lower 48 states and Alaska.

° AD = Accelerated Development

° Production is given in trillion of cubic feet per year

2/ Minimum acceptable oil price is given in constant 1973 dollars per barrel, inasmuch as associated--dissolved natural gas is produced in conjunction with crude oil.

The analyses lead to the following conclusions:

1. Because of the long lead-times required to bring natural gas production on stream, and because of anticipated declining finding rates, non-associated gas production from the lower 48 states should continue to decline until nearly 1980, regardless of price.

2. At a minimum acceptable price of $1.00 per MCF under BAU conditions, non-associated marketed production could increase from 16.7 TCF per year in 1974 to 18.1 TCF per year in 1985. The major sources of new gas would be in the offshore and onshore Gulf Coast region.

3. Under AD conditions, at a minimum acceptable price of $1.00 per MCF, marketed production could reach 21.3 TCF per year in 1985. Among the sources of further increases in non-associated gas production over the BAU case would be the Atlantic and California OCS.

4. Associated-dissolved gas production levels from the lower 48 states and southern Alaska OCS would depend significantly on oil prices. The 1974 production levels of 3.7 TCF per year would be reduced in 1977 at prices of $7 or less per barrel under both BAU and AD assumptions, but would increase in 1985. At $11 per barrel oil prices, associated-dissolved gas production would increase substantially over $7 levels.

5. Non-associated gas from both Alaskan regions and associated-dissolved gas from the North Slope could provide major quantities of new gas production. In 1974, this production amounts to only 0.1 TCF. per year. At oil prices of more than $7 per barrel, production under BAU conditions could reach 1.9 TCF per year in 1985, while production under AD conditions, with the development of NPR-4 and additional OCS leasing, could reach 3.6 TCF per year by 1985. The inclusion of transportation costs to the lower 48 states' markets would significantly affect prices.

6. Under the AD scenario, production of gas from tight formations would depend on successful development of recovery technology, but, if successful it could provide as much as 2.0 TCF per year in added gas production by 1985. The amount of gas recoverable from coal seams is forecast to be negligible.

7. If natural gas prices remain regulated at current levels, the outlook for increased gas supplies is not promising. At the current field price, wellhead production in 1985 could decline by over 6 TCF per year from 1974 levels (a decline of almost 30 percent). The share of natural gas in interstate markets would also be drastically reduced. The effects of price regulation predominantly impact non-associated gas.

Sensitivity analyses were performed to reflect uncertainties involved in estimating natural gas production. Finding rates were uniformly increased and decreased by 20 percent in these analyses, and discovery volumes differed from the BAU case by about 20 percent. Corresponding regional minimum acceptable prices were approximately 16-20 percent less with the higher finding rates and 24-28 percent higher with lower rates, indicating the considerable price sensitivity to finding rates.

In other sensitivity analyses, the after-tax rate of return on investment was set at 15 percent and 7.5 percent, resulting in price increases of 28-33 percent in the former case,and price decreases of 13 to 18 percent in the latter. Inclusion of lease bonus and rental costs increased prices by about 10 percent in onshore areas and by 36 to 265 percent, depending on the year and location in offshore areas, indicating the high degree of sensitivity of minimum acceptable prices.

"OIL: ITS TIME ALLOCATION AND PROJECT INDEPENDENCE," BROOKINGS PAPERS ON ECONOMIC ACTIVITY, NO. 2, 1974 PP. 411-448

PAUL DAVIDSON
Rutgers—The State University

LAURENCE H. FALK
Rutgers—The State University

HOESUNG LEE
Rutgers—The State University

Oil: Its Time Allocation and Project Independence

IN 1973, THE onset of an energy crisis in a world that for a century had been plagued by potential oversupply of fossil fuels at existing market prices caught many knowledgeable observers by surprise. The energy shortage immediately generated a search for a scapegoat or a rational explanation of the predicament of the highly developed, capitalist economies, heavily based on energy resources, of the United States, Western Europe, and Japan.

According to Leonard Silk, the mammoth multinational energy companies, afflicted by the same "pea-sized brain" that proved fatal to the dinosaurs, either caused or exacerbated the problem. His analysis depicted corporate mastodons as relentlessly pursuing the goal of profit maximization; but it concluded that since "economics is not everything," society cannot be at the mercy "of corporations that have no other purpose than

profit-maximization, however legitimate and useful that objective may be in a limited context."[1]

Yet orthodox economic theory has taught that, given the right background assumptions, businessmen's single-minded pursuit of profit opportunities, tempered by competition and the absence of externalities, would result in an efficient and optimum allocation of resources and the maximization of the welfare of the community. Thus, contrary to Silk's condemnation, executives of multinational energy companies should not be pilloried for failing to meet the needs of any one selfish nation, for in their pursuit of profit maximization, they are unwittingly maximizing the economic welfare of mankind. Responding to comments on the lack of competition at various stages of the vertically integrated oil industry, some students of the industry claim that the international supply of crude oil is "the same as what might be expected to arise from the operation of the law of comparative costs in a freely competitive international market."[2] After all, the consumer seemed to be plentifully, and cheaply, supplied.

Even now that more economists are willing to acknowledge how noncompetitive the oil-resource market is, many continue to envision the problem of depletable fossil fuels in terms of determining the "optimal social management of a stock of a nonrenewable but essential resource."[3] An immediate consequence of this way of conceptualizing the problem is to analyze the existing structure of the resource market to see whether it provides "proper" price allocative guidelines. If it can be proven that the market "fails," then it follows (for those who use this approach) that the role of the economist is to design policies to improve market performance and bring it closer to the competitive ideal. In other words, the first instinct of many economists in this field is to leave the decision as to the time rate of exploitation of exhaustible resources to the invisible hand, unless a market failure can be demonstrated *and* a corrective policy can be developed.

1. Leonard Silk, "Multinational Morals," *New York Times*, March 5, 1974.

2. J. E. Hartshorn, *Politics and World Oil Economics: An Account of the International Oil Industry in Its Political Environment* (Praeger, 1962), p. 340. Even in 1974 studies have been produced to show that "prices paid by consumers for petroleum products reflect the actual costs of suppliers and are not 'padded' by excess profits. The competitive process has held industry profits down." See Edward J. Mitchell, *U.S. Energy Policy: A Primer* (Washington: American Enterprise Institute, 1974), p. 103.

3. Robert M. Solow, "The Economics of Resources or the Resources of Economics," in American Economic Association, *Papers and Proceedings of the Eighty-sixth Annual Meeting, 1973* (*American Economic Review*, Vol. 64, May 1974), p. 2.

In the first section of this paper we deal with two related issues: First, can market prices, even in a competitive environment, provide adequate guidelines for approaching an efficient and optimal rate of utilization of exhaustible resources? Second, in a world of conglomerate energy companies, does rationality of entrepreneurial policies imply anticompetitive and antisocial behavior that redistributes income from consumers to producers and owners of resource-bearing property? Some policy implications inevitably follow from this analysis.

The second section presents our estimates of the market price for crude oil required to achieve the stated goal of Project Independence: self-sufficiency by 1980.[4] Since the first section attempts to demonstrate that for policy purposes economists who seek to determine the efficiency of any given time rate of exploitation of oil properties only waste their own resources, it follows that no one can tell whether Project Independence is on a socially optimal management path—that is, whether self-sufficiency in 1980 will maximize the sum of discounted consumer and producer surpluses. But once self-sufficiency is established as a desirable goal by society's decisionmakers, economists can examine alternative paths to that objective and their implications for prices, income distribution, and production flows.[5]

In the second section we have estimated the 1980 market-clearing, long-run price necessary to achieve self-sufficiency, given the historical supply and demand elasticities for petroleum. A sensitivity analysis of this estimate to variations in supply and demand elasticities is also presented.

Market Prices and Exhaustible Resources

In a recent paper William Nordhaus not only succinctly summarized the foundation for the orthodox economic belief in the desirability of a laissez-faire approach to exhaustible-resource pricing, but also attempted to simu-

4. "The Energy Emergency," The President's Address to the Nation, November 7, 1973, in *Weekly Compilation of Presidential Documents*, Vol. 9 (November 12, 1973), pp. 1312–22.

5. It is our belief that economists should acknowledge their role as "soft" scientists providing advice to policymakers regarding "hard" decisions. Moreover, even as soft scientists we do not hesitate to suggest that policy should aim at (1) protecting consumers from paying more than the normal supply price for essential goods and services, and (2) encouraging "Enterprise" and preventing "Speculation" from dominating economic activities.

late how such a pricing system would tend to allocate, over the next 200 years, the known recoverable energy resources of the world.

The theoretical foundation for Nordhaus' analysis relies on the theory of general economic equilibrium. It assumes

consumers with initial resources and given preferences, and producers operating with well-defined technical relations. . . . [It] can embrace many time periods and uncertainty about the exact demand or supply conditions; but it assumes convex production and preference sets, and that markets exist for all goods, services, and contingencies. . . . [including] futures markets for, say, petroleum and coal in the year 2000; and . . . insurance markets for such contingencies as the failure of breeder processes to become economically viable. Also, all the costs and benefits of a particular process of production must be internalized to the decision maker. Under the above conditions a market system will have a general equilibrium of prices and quantities. . . . [T]he equilibrium will be efficient in the sense that there is no way of improving the lot of one consumer without worsening the lot of another. Expressed differently, the prices are appropriate indicators of social scarcity. . . .[6]

Although many economists subscribe to the general-equilibrium notion that market prices can allocate energy resources efficiently over time, others such as F. H. Hahn have noted that the theory of general economic equilibrium can only be used as an argument *against* someone

. . . who maintains that we need not worry about exhaustible resources because they will always have prices which ensure their "proper" use. . . . A quick way of disposing with the claim is to note that an Arrow-Debreu equilibrium must be an assumption he is making for the economy and then to show why the economy cannot be in this state. The argument will here turn on the absence of futures markets and contingent futures markets and on the inadequate treatment of time and uncertainty. . . . This negative rôle of Arrow-Debreu equilibrium I consider almost to be sufficient justification for it, *since practical men and ill-trained theorists everywhere in the world do not understand what they are claiming . . . when they claim a beneficent and coherent rôle for the invisible hand. . . .*

. . . [Since] we know that these [futures] markets are in fact very scarce [and] . . . some contingent markets could logically not exist . . . *we can easily refute propositions* [*like these*] *on exhaustible resources*. . . . Moreover one can locate precisely where the argument goes wrong.[7]

A "proper" use of any exhaustible resource requires entrepreneurial decisions on the time rate of its production. The market price system can

6. William D. Nordhaus, "The Allocation of Energy Resources," *Brookings Papers on Economic Activity* (3:1973), pp. 530–31. Hereafter this document will be referred to as *BPEA*, followed by the date.

7. Frank H. Hahn, *On the Notion of Equilibrium in Economics* (London: Cambridge University Press, 1973), pp. 14–16 (emphasis supplied).

provide guidance on an optimal resource allocation over time only under the following conditions:

1. Well-organized forward markets exist *for each date* in the future.

2. Consumers know *with actuarial certainty* all their needs of energy resources *at each date.*

3. Consumers are able and willing to exercise all these future demands by currently entering into forward contracts *for each date.*

4. Entrepreneurs know *with actuarial certainty* the costs of production associated with production flows *for each date.*

5. Sellers can choose between an immediate contract at today's market price and a forward contract at the market price associated with any future delivery date (over 73,000 in the Nordhaus model).

6. Entrepreneurs know *with actuarial certainty* the course of future interest rates.

7. The social rate of discount equals the rate at which entrepreneurs discount future earnings and costs.[8]

8. *No false trading* occurs—that is, no production or exchange ever takes place at nonequilibrium prices.[9]

If all these conditions are met, then in a competitive environment, market prices can be shown to be an efficient or socially optimal way to allocate energy resources over time, in the sense of maximizing the sum of discounted consumer and producer surpluses.

Since for any particular property, the fossil fuels in the ground are a fixed inventory (or exhaustible resource), the more used today, ceteris paribus, the less will be available for future delivery. Consequently, a

8. This condition can hold only if monetary and fiscal policy are so precisely applied that they eliminate any divergence between the natural rate of interest and the market rate of interest. See Kenneth J. Arrow, "Discounting and Public Investment Criteria," in Allen V. Kneese and Stephen C. Smith (eds.), *Water Research* (Johns Hopkins Press for Resources for the Future, 1966), pp. 13–32.

9. The absence of false trading is an esoteric but essential condition for the beneficence of the invisible hand. In the real world of uncertainty, however, false trades are inevitable and hence those who look to market prices to allocate energy resources properly over time are pursuing a will-o'-the-wisp.

Currently, general-equilibrium theorists utilize the assumption of a complete set of futures markets for all contingent commodities to eliminate uncertainty and false trades from their models. This is merely a logical dodge for it requires that contracts for all contingent commodities be entered into at market-clearing prices at the initial date—that is, all possible human agreements for every contingency involve prices that reconcile all plans and expectations before any production and exchange occurs *and* no additional contracts can be entered into for the rest of time.

rational entrepreneur will compare the present value of expected profits for a forward contract sale at each possible future date with the profitability of selling that amount today. If profit-maximizing entrepreneurs are to produce for current sale, current marginal revenue must be expected to cover not only current marginal factor costs associated with that barrel of oil but also the *user costs inherent in all depletable resources*—namely, the highest present value of marginal future profits given up by producing that barrel of oil currently rather than in the future.[10] Thus, for example, Nordhaus attempts to simulate the allocation arising from a complete set of spot and forward market prices assuming that (1) the 1970 information about supply availability and costs was accurate and relevant for each time period for the next two centuries, and (2) energy demands over the foreseeable future could be projected from the 1929–68 historical growth rates (ignoring price elasticity effects).[11]

As Nordhaus recognizes,[12] forward markets for most commodities do not exist and, as Hahn has noted, they cannot logically exist in the real world where the future is yet to be created. Arrow has attributed the failure

10. For a complete discussion of user costs and petroleum production, see Paul Davidson, "Public Policy Problems of the Domestic Crude Oil Industry," *American Economic Review*, Vol. 53 (March 1963), pp. 85–108; also see Robert G. Kuller and Ronald G. Cummings, "An Economic Model of Production and Investment for Petroleum Reservoirs," *American Economic Review*, Vol. 64 (March 1974), pp. 66–79.

As Champernowne has indicated, Keynes borrowed the term "user cost" from Marshall, but was the first to develop the concept and apply it to the question of intertemporal production from depletable properties. See D. G. Champernowne, "Expectations and the Links Between the Economic Present and Future," in Robert Lekachman (ed.), *Keynes' General Theory: Reports of Three Decades* (St. Martin's, 1964), p. 177; and John Maynard Keynes, *The General Theory of Employment, Interest and Money* (Harcourt, Brace, 1936), pp. 66–73. Since then many other authors have refined the user-cost concept to analyze entrepreneurial decisions about the timing of production in the short run. See, for example, Joe S. Bain, "Depression Pricing and the Depreciation Function," *Quarterly Journal of Economics*, Vol. 51 (August 1937), pp. 705–15; Alfred C. Neal, *Industrial Concentration and Price Inflexibility* (American Council on Public Affairs, 1942), pp. 58–61; Sidney Weintraub, *Price Theory* (Pitman, 1949), pp. 378–81; A. D. Scott, "Notes on User Cost," *Economic Journal*, Vol. 63 (June 1953), pp. 368–84; Anthony D. Scott, "The Theory of the Mine Under Conditions of Certainty," in Mason Gaffney (ed.), *Extractive Resources and Taxation* (University of Wisconsin Press, 1967), pp. 34–41; M. Mason Gaffney, "Soil Depletion and Land Rent," *Natural Resources Journal*, Vol. 4 (January 1965), pp. 537–57; and M. A. Adelman, *The World Petroleum Market* (Johns Hopkins University Press for Resources for the Future, 1972), p. 40.

11. Nordhaus, "Allocation of Energy Resources," pp. 537–41.

12. Ibid., p. 534.

of real-world economies to develop forward markets in most goods[13] to the costliness of enforcing forward contracts to dates far in the future, and the unwillingness of buyers and sellers to make forward contractual production and purchase commitments.[14] Even if one is willing to overlook what Arrow terms the "failure of markets for future goods" in attempting to model an "efficient" time path that might apply in the presence of futures markets (as Nordhaus does), the necessary assumption that no false trading occurs dooms the search for an efficient allocative mechanism that relies on market prices. If false trading occurs, the parameters of the economy change and it is extremely unlikely that the original set of equilibrium spot and forward prices over time will continue to provide an efficient solution—or that any other set can.

In the past, general-equilibrium theorists such as Hicks have avoided the devastating conclusion that economists cannot say anything meaningful about efficient resource use over time by merely assuming that false trading is negligible. Hicks justified this assumption by shortening the time horizon—to less than a day if necessary.[15] But, then, those who advocate a market-price solution for allocating exhaustible fossil fuels over years, decades, or even centuries cannot use general-equilibrium theory to justify their position.

Many economists ignore these formidable issues by developing models for a world of certainty with a specified time horizon. Other economists merely assert that resource markets in the real world normally behave much as they would in a world of certainty, and that therefore general-equilibrium models are a useful "parable" for analyzing the efficient time rate of exploitation of exhaustible resources. For example, Solow states: ". . . in tranquil conditions, resource markets are likely to track their equilibrium paths moderately well, or at least not likely to rush away from them. . . .

13. Kenneth J. Arrow, "Limited Knowledge and Economic Analysis," *American Economic Review*, Vol. 64 (March 1974), p. 8.

14. In fact, however, long-term (often perpetual) leases are the rule for properties that bear natural resources.

But many of those who will be buyers in the future may at any given time be yet unborn; or, if already alive, too young to enter into the contracts necessary to convert future wants into demand, or uncertain how much energy resources they will need in the future. Under these circumstances a free market system could not allocate energy resources over decades or centuries to achieve Pareto efficiency even if a complete set of futures markets for all contingent commodities existed.

15. J. R. Hicks, *Value and Capital: An Inquiry into Some Fundamental Principles of Economic Theory* (2d ed., Oxford University Press, 1946), p. 129.

[Of course] resource markets may be rather vulnerable to surprises. . . . It may be quite a while before the transvaluation of values . . . settles down under the control of sober future prospects."[16] This belief in "tranquil conditions" and the ultimate dominance of "sober" minds in the long run—in short, the stability of expectations—is the bedrock of the neoclassical view that the competitive market may yet, with sufficient empirical study and analysis, yield the secret of determining the socially optimal exploitation of exhaustible resources over time.

One of the more ingenious attempts at developing such a scenario for energy-resource use over time has been Nordhaus' monumental study. Nordhaus' work has been described as an analysis of ". . . how energy requirements will be met in the long run, . . . [and of] the pattern of uses and prices of various types of energy that would emerge through time in a free competitive market. While he acknowledges some of the ways in which actual prices may differ from those generated by his model, he regards his general outline of resource utilization and price changes as helpful indicators of how the future of energy use is likely to unfold."[17] Nordhaus notes that in his model "the price system is ex ante efficient as long as a complete set of futures markets exists."[18] He recognizes that the absence of these markets might create "serious problems," but he argues that "an estimate of whether current usage is too fast or too slow cannot be made a priori; it can emerge only from a carefully constructed econometric and engineering model of the economy."[19]

Here we must disagree.[20] As Shackle has pointed out, "the existence of 'futures' markets is a mere technical gloss on the essential situation,"[21] since speculators enter into contracts in futures markets because they *disagree* with the market's valuation of the future. Hence when the future

16. Solow, "Economics of Resources," p. 7. In correspondence regarding this paper, Solow has indicated that he accepts the view that an optimal strategy is a will-o'-the-wisp. Nevertheless, he maintains that it is possible to judge that some intertemporal allocations are better or more efficient than others with a high degree of probability.

17. Arthur M. Okun and George L. Perry, "Editors' Introduction and Summary," *BPEA* (3:1973), p. 516.

18. Nordhaus, "Allocation of Energy Resources," p. 534.

19. Ibid., p. 537.

20. This is not to deny Nordhaus' conclusion about the immense *availability* of fossil fuels! And Nordhaus has described at least one possible scenario for the future. But this scenario has nothing to do with an optimal path in the real world.

21. George L. S. Shackle, *Epistemics & Economics: A Critique of Economic Doctrines* (Cambridge, England: Cambridge University Press, 1972), p. 111.

becomes the present, either the speculators or the market, or both, will have been in error and false trading (surprises) will have occurred. As long as the future is uncertain individual opinions about it are free to diverge from each other and from the pronouncements of any market. False transactions are an inevitable and ubiquitous phenomenon in the real world.

"[The] *long run* is a misleading guide to current affairs. *In the long run* we are all dead. Economists set themselves too easy, too useless a task if in tempestuous seasons they can only tell us that when the storm is long past the ocean is flat again."[22] Any attempt to provide policymakers with guidelines for solving real-world problems such as the energy crisis using assumptions of "a world of certainty" or "values under the control of sober future prospects" or "tranquil conditions," is, in our view, almost fruitless, and may be positively mischievous in that it may mislead practical men into claiming "a beneficent and coherent role for the invisible hand."

Because futures markets do not exist; because even if they did, false trading would occur in a world of uncertainty and change; and because estimates of future demands and costs are at best unreliable, it is impossible to specify any time rate of exploitation of resources that will be efficient or maximize the sum of discounted consumer and producer surpluses over any long period.

The a priori inability of market prices to provide any guideline for such allocation does not relieve producers from the responsibility of deciding the actual rate for exploiting these resources. Some economists, recognizing the hopelessness of specifying any policy for socially optimal resource management, have argued that "the mere statement of the problem . . . serves to support a general disposition to leave these complicated calculations to the self-interest of businessmen in competitive markets,"[23] in the delusive hope that the inevitable errors of many decisionmakers will tend to cancel out. In the early sixties, this view was not hard to accept, provided the government assured the existence of competitive markets, required field unitization, and removed certain favorable tax treatments. In the midst of a worldwide "energy crisis," leaving energy-resource production to businessmen's subjective estimates of user costs seems much less desir-

22. *A Tract on Monetary Reform*, Vol. IV, *The Collected Writings of John Maynard Keynes* (London: Macmillan, 1971 ed.), p. 65.

23. Melvin G. de Chazeau and Alfred E. Kahn, *Integration and Competition in the Petroleum Industry* (Yale University Press, 1959), p. 236.

able. Current market conditions are likely to encourage all producers to expect rapid increases in prices (as a reflection of growing monopoly elements rather than of increasing social value), and such views will nurture monopoly growth with its concomitant redistribution of income from consumers to producers and ultimately to property owners in the form of economic rents. While some may disagree, we judge such a redistribution to be undesirable as well as unnecessary. Accordingly, we now believe that in the absence of omniscient producers or governments, the damage is likely to be minimized by the adoption of policies that eliminate positive user costs as an element in production decisions.

USER COSTS IN THE ABSENCE OF FORWARD MARKETS

In the absence of developed futures markets, producers' subjective expectations of the user costs inherent in all raw materials are major determining factors in the time rate of exploitation of energy resources. Given the time period, as long as the expected rate of increase in the difference between price and average factor costs is equal to the expected rate of interest, the marginal user cost is zero, and profit-maximizing managers will produce up to the point where current price equals the remaining marginal factor costs *plus* a markup or profit margin whose magnitude depends on the degree of monopoly the producers have in the marketplace.[24] (If producers operated in a purely competitive market, price would simply equal marginal factor costs.)

If, however, for the future, price is expected to increase relative to production costs at an annual rate beyond the expected rate of interest, marginal user costs will be positive and current production will be reduced as producers withhold some energy resources to sell at a greater "discounted" profit at a future date. Finally, if prices are expected to decrease relative to costs (or to increase at less than the rate of interest), marginal user costs will be negative and current production will be higher than when marginal user costs are zero. Thus, in a world of uncertainty, we are left with a bootstrap theory of the time rate of exploitation of energy resources; current expectations of producers play the pivotal role in the absence of any "facts" about the future. Consequently, relative stability over time in prices and production in energy-resource markets requires that most pro-

24. The degree of monopoly power can be measured by $m = (P - MC)/P$, where P is current price and MC is marginal factor costs.

ducers think that tomorrow will not be significantly different from today, although it can perhaps accommodate some divergency of views among producers.

If, however, most producers expect that the relation of prices to costs will change significantly in an uncertain future, energy-resource markets will be dominated by speculative activities. Since solid information about that future *cannot* exist, the result is bound to be detrimental to society. "Speculators may do no harm as bubbles on a steady stream of enterprise. But the position is serious when enterprise becomes the bubble on a whirlpool of speculation."[25]

Until recently, state and federal governmental policies prevented rapid changes in wellhead prices in the United States. Market prorationing supported by the 1935 federal law, popularly known as the Connally Hot Oil Act, which prohibits interstate commerce in oil that was produced in violation of state prorationing laws, plus the operation of import quotas, effectively eliminated any positive user costs. At the same time, speculation in the international market was restrained by the ability of the "Seven Sisters" (the seven largest international oil-producing companies) to maintain an orderly market. However, most sellers of energy resources have been led to expect rapidly rising prices by the events of the early seventies—including the relaxation of market-demand prorationing; the growth of the power of the oil cartel, the Organisation of Petroleum Exporting Countries (OPEC), at the same time that import quotas were being removed; the unsettled politics of the Middle East. These events have stimulated speculative proclivities and consequently retarded current production of fossil fuels.

Current statistics from the U.S. Geological Survey (USGS) provide strong evidence of speculative withholding of oil production. Completed shut-in oil-producible zones[26] offshore jumped from 953 in 1971 to 2,996 in 1972 and 3,054 in 1973, while active oil wells fell from 5,704 to 3,814 over this period, even though new wells continued to be completed at a rate of 300 to 400 per year.[27] This jump in shut-ins from 14 percent of

25. Keynes, *General Theory*, p. 159.

26. A completed shut-in producible zone is an area in which a well has been drilled and has been determined by USGS to be capable of producing *in paying quantities*, but for which a suspension of production has been certified by USGS. There may be more than one producible zone associated with a single well.

27. U.S. Geological Survey, Conservation Division, *Outer Continental Shelf Statistics* (June 1974), pp. 29, 34–36. For a further discussion of the importance of the shut-in oil producible capacity, see the section, "A Final Caveat," below.

producible zones in 1971 to over 44 percent in 1972 does suggest an explicit decision by producers to restrict available production flows. Moreover, since producers can restrict oil production not only by a complete shut-in of oil wells but also by reducing flows from producing wells, shutting in associated gas wells, and slowing down drilling activity on wells nearing completion, and since the shut-in statistics cover only offshore completed oil-producible zones, speculative withholding may be significantly greater than these statistics suggest.[28]

If this speculation is unwarranted—that is, if producers' expectations do not properly reflect the relative valuation of buyers and the costs of producing energy resources for future use vis-à-vis their present use (and in an uncertain world there is no reason why they can or should)—then governments must act to prevent such profit-maximizing speculative activity from harming today's society. Stability in today's energy markets may be a humbler goal than the efficient allocation of energy resources over the long run but, at least, it is achievable.

In the current "energy crisis" two major factors have spurred speculative excesses in the energy market. These are the growth of the monopoly power of the OPEC cartel, and the development of conglomerate energy companies.

OPEC AND USER COSTS

OPEC oil has always been sold by producers who had not only significant monopoly power in product markets, but also, in the past, monopsony power in the market for oil-bearing properties. The existence of large monopoly rents, as well as the possible withholding of diminishing-return rents by monopsonist producers on properties in the OPEC nations, has now encouraged the host nations to attempt to capture some of these rents

28. A recent Federal Power Commission study of 168 offshore shut-in producible gas leases has conservatively estimated that these properties contain proved reserves of 4.7 billion mcf (thousand cubic feet) and an additional 3.3 billion mcf in probable reserves, a total two-and-one-half times actual offshore production in 1973. A significant portion of these gas reserves is in wells associated with producible quantities of oil. Over two-thirds of these 168 shut-in leases are more than five years old. The FPC staff is attempting to determine why rational producers would develop these properties and then shut them in. See U.S. Federal Power Commission, Bureau of Natural Gas, *Offshore Investigation: Producible Shut-in Leases (First Phase), January 1974* (March 1974), and *Offshore Investigation: Producible Shut-in Leases As of January 1974 (Second Phase)* (July 1974).

for themselves.[29] As long as the host nations competed with each other to grant concessions, however, they could receive the diminishing-returns rents at best. But once they organized a cartel, the market for OPEC properties became a type of bilateral monopoly situation, where the distribution of the total economic rents (of both sorts) is not determinate. Thus, as a number of experts have noted, the dispute between the operating companies and the African and Middle East governments "essentially, in economic terms, . . . is a question of the division of economic rent."[30]

As landowners in the Middle East and Africa realized that large economic rents had escaped them because of their acceptance of the original concession contracts, they urged the formation of the OPEC cartel as a remedy. If, of course, the operating companies were passively to acquiesce in giving the landowners the economic rents that, under the initial contracts, had been their own, then, ceteris paribus, the actual degree of monopoly in the product market would remain unchanged and so would the price to consumers.

But suppose that host nations are now attempting to capture both diminishing-returns rents *and* the monopoly rents in the product market. As Chamberlin has demonstrated, competition for properties among producers makes landlords the ultimate recipient of all monopoly rents.[31] If the price elasticity of demand in the product market (that is, the degree of monopoly) was unchanged and if producers were already profit maximizing in the product markets, then consumer prices would not change. In this case again, the only effect of the OPEC cartel would be to redistribute the largesse of economic rents from the companies to the host nations.[32]

If, however, some unexploited monopoly power remains in the product market, the companies can attempt to recoup the higher payments to landowners from the ultimate consumers. Their success will depend on the

29. In a perfectly competitive property market, the present value of lease bonuses and future royalties would exactly equal the discounted values of these economic rents so that all diminishing-return rents would accrue to property owners. If producers had monopsonistic power either because of superior information or collusion on bids, they could keep some of these economic rents.

30. Michael V. Posner, *Fuel Policy: A Study in Applied Economics* (London: Macmillan, 1973), p. 52.

31. Edward H. Chamberlin, *The Theory of Monopolistic Competition: A Re-orientation of the Theory of Value* (7th ed., Harvard University Press, 1960), pp. 266–69.

32. This result still might cause balance-of-payments problems for the consuming nations, but as long as the OPEC nations are attempting merely to capture existing economic rents, their actions will not affect long-run marginal factor costs.

price elasticity of demand of the consuming nations for OPEC oil.[33] As long as either this demand is relatively inelastic, or additional monopoly power can be brought to bear,[34] the operating companies will have a strong incentive to extract from consumers the net revenues lost in monopoly rents to the host governments. In fact, as the host nations have increased their receipts per barrel, the operating companies have raised product prices by an even greater absolute amount. For example, when the Persian Gulf nations raised their payments by the equivalent of 28 cents per barrel in February 1971, the matching price increase in Britain was 42 cents per barrel;[35] thus the net revenues of the operating companies increased as they drew on previously unexploited monopoly power.

The incentive to form a coalition to limit supply and to convince the consuming nations that there is an energy crisis can be analyzed via the user cost inherent in all raw materials that involve these kinds of latent market power. If at or near current price levels the consumer has no good substitute from suppliers who have no economic interest in maintaining the potential monopoly rents for OPEC oil, and if governments of consuming nations leave the market unfettered, then the demand for OPEC oil will provide the possibility of additional exploitable monopoly rents. If OPEC oil suppliers—whether host nations or operating companies—believe that, by enforcing market sharing and production restrictions, a cartel can exploit additional market power by raising the prices to the consuming nations over time, then the marginal user cost is positive. Hence producers and landowners (who via royalties and taxes have a vested interest in higher prices) will pursue policies to restrict current production as long as incremental revenues are exceeded by incremental costs, including this

33. The elasticity of demand for OPEC oil will depend on the availability of substitutes provided by suppliers who have no interest in maintaining economic rents for OPEC oil. This point is developed below.

34. In a world of perfect certainty, profit-maximizing entrepreneurs would not leave monopoly power unexploited. In the real world, however, producers in the oil industry may be more interested in maintaining market shares than in maximizing profits. Producers may not always set profit-maximizing prices for fear of antitrust or other governmental action. In the absence of significant justifications for increases, prices may remain stable below profit-maximizing levels until they are released by severe market shocks, like the closing of the Suez Canal or the unified demands of OPEC. Then, in a world of uncertainty, where political crises can reduce the effectiveness of government responses to price increases producers may exploit latent monopoly power and also try to stimulate political and expectational conditions that create additional monopoly power.

35. The data on price increases are from the McGraw-Hill publication, *Platt's Oilgram News Service*, Vol. 49 (February 18, 1971), p. 2, and (February 23, 1971), p. 1-A.

positive user cost, as they attempt to capture potential additional monopoly rents from consumers. The consumer must then either find a way to reduce the user costs to zero or else accept the higher price as tribute to the monopoly power of the suppliers.

CONGLOMERATE ENERGY COMPANIES AND USER COSTS

How has the growth of conglomerate energy companies affected the ability of the OPEC cartel to create positive user costs?

As has already been intimated, the existence of an exploitable monopoly position depends on the present and future price elasticity of demand in the relevant range. As far as the OPEC cartel is concerned, therefore, it depends in large measure on the current price in consuming countries and ultimately on the supply price at which alternative sources of energy will become significant substitutes for OPEC oil. Suppose, however, the supplier of a substitute energy source also has an economic interest in OPEC petroleum reserves, because it is a conglomerate energy company with an OPEC concession or other oil reserves. Then it will anticipate a positive user cost in providing the substitute if production of this substitute reduces potential profits from its oil reserves. This positive user cost will raise the supply price (above resource costs) of marketing the substitute.

In these circumstances this positive user cost of substitutes internalizes a cost that in a competitive economy would be external to an independent producer of a substitute energy source. Independent producers of domestic oil, shale, tar sands, coal, uranium, and so on, would not care if they inflicted capital losses on the value of foreign underground reserves of petroleum by providing a cheaper energy source. Most reasonable people would argue that society is the beneficiary of a decision to produce a less expensive substitute even though the oil producers and property owners would suffer a capital loss. The existence of rational, multisource, energy-producing conglomerates, however, constrains production of substitute fuels and reduces consumer welfare. The ability of conglomerates to maintain high prices for the substitutes tends to reinforce their monopoly power in marketing their OPEC oil.

If at the current price consumer demand for OPEC oil is therefore still in the exploitable range, a strong cartel of property owners can allow multinational energy conglomerates to continue to raise prices relative to real resource costs. The continuous revenue increases of host nations since 1970 seem to be attempts to search out the point at which demand for

OPEC oil becomes so elastic that monopoly rents are fully exploited. (However, for any given demand situation with any degree of elasticity, higher prices require production restrictions, and hence at least tacit market-sharing arrangements to prevent one member of the cartel from increasing its gains at the expense of others.) Since the operating companies also have vested interests in the price of OPEC reserves as long as they retain any monopoly rents, they will be willing tools in maintaining an "orderly" production market.

If, however, the operating companies expected the host nation to nationalize the reservoirs soon without adequate compensation for their economic interests, the user costs of OPEC reserves would become negative *to the producing firms*, and they would try to increase the production flow even if that would drive down current prices to resource costs and destroy their market power. Thus, threats of nationalization without adequate compensation can only be detrimental to the interests of host nations, while favoring consuming nations.

POLICY IMPLICATIONS OF USER COSTS

In the light of recent experience, OPEC nations seem likely to pursue their attempts to capture more of the monopoly rents, and the companies their efforts to exercise all the available monopoly power in consumer-nation markets. Furthermore, even if no additional monopoly power remains to be exploited in the consuming nations but if the OPEC cartel is intact, monopoly rents will be redistributed from the operating companies (which are basically residents of the consuming nations) toward the OPEC nations, causing balance-of-payments problems and perhaps adverse changes in the terms of trade among the consuming nations.[36] In such an ultimate situation, the operating companies would act as monopoly tax collectors for OPEC as all the monopoly rents are transferred to the host nations.[37]

Since expectations of price-cost relations can, via the user cost inherent in all depletable resources, dictate the rate at which OPEC exploits its large

36. The loss in real income of the consuming nations resulting from this redistribution may take the form of high unemployment if the OPEC nations do not spend all of their claims on world income, and if the governments of the developed nations do not undertake compensating expansionary policies.

37. See Adelman, *World Petroleum Market*, p. 256.

underground reserves in its search for maximum economic rents, user-cost expectations become crucial to the apparent worldwide energy crisis. The OPEC strategy on user costs depends on OPEC's view of the growth in demand of the consuming nations, and its estimates of the timetable and prices at which known and potential substitutes can be marketed.

User costs cut both ways—that is, expectations of higher prices tend to retard current exploitation of known OPEC reservoirs and exacerbate supply shortages, while expectations of lower prices will accelerate exploitation. In other words, if the OPEC countries expected the price of oil to decline over the next dozen years, they would want to augment the flow of oil now to take advantage of the higher prices available today and tomorrow. Hence the best interests of the consuming nations lie in policies that encourage the expectation of a decline in the price of OPEC crude by, say, 1980.

Accordingly, consuming nations should devise policies aimed at reducing the degree of monopoly in the energy-products market, or at least at containing it; and at breaking up the OPEC cartel to prevent redistribution of economic rents and the worsening of the terms of trade.

A policy for substitutes and curbing monopoly power. For consuming countries such as the United Kingdom, the United States, Western Europe, and Japan, the availability of substitutes rests on indigenous energy sources with low resource costs or importation of oil from low-cost, non-OPEC, regions.

Large additional reserves are unlikely to be available in the next decade from non-OPEC nations that are not themselves major consumers; and even if they were, such host nations would probably find their own self-interest more compatible with joining OPEC than with attempting to lick it by underpricing its oil. Moreover, OPEC would probably see that its self-interest was best served by accommodating these countries and sharing the fruits of the cartel with them. Hence the consuming nations are unlikely to find cheap substitutes for OPEC oil among other Third World countries.

Thus the major substitutes are oil and gas and other energy resources from properties within the boundaries of consuming nations or the adjacent continental shelf. Moreover, these substitutes should be developed by independent producers who have no vested interest in maintaining or improving the capitalized value of already proved oil reserves.

Accordingly, consumer nations such as the United States who happen to own most of the remaining unexplored potential fossil fuel-bearing

properties within their national boundaries[38] should adopt policies that accelerate leasing of offshore tracts and shale lands, and that promote development of the properties by independent producers and government energy corporations.[39] Such policies would reduce the existing degree of monopoly in product markets and permit some intramarginal lands (which are being withheld by government edict) to be developed before forcing producers to move further out along the extensive margin. Further, requirements for rapid development and exploitation would diminish the ability of producers to maintain monopoly power in the product market by limiting production.

Increasing rates of exploitation of new reservoirs. If large new fields in consuming countries are currently coming on stream—for example, in the North Sea and Alaska—an announced policy of rapid exploitation, even at rates that exceed the maximum efficient rate of production (MER),[40] will induce expectations of a decline in the price for OPEC oil. These expectations will be strengthened if an available substitute, such as shale or nuclear

38. The USGS estimates that the lower forty-eight states contain between 575 billion and 2.4 trillion barrels of oil reserves, while current proved reserves are only 37 billion barrels. See Sanford Rose, "Our Vast, Hidden Oil Resources," *Fortune*, Vol. 89 (April 1974), pp. 104–05. T. H. McColloh has reported that *economically recoverable* (at 1970–71 wellhead prices) oil reserves in the United States are from about three-and-one-half to ten times current proved reserves as reported by the industry. See *United States Mineral Resources*, USGS Professional Paper 20 (1973), pp. 491, 492. Since these two sets of estimates were made when wellhead prices were much lower, they significantly underestimate current economically recoverable reserves.

39. A change in the base contract from the constant-percentage royalty and front-loaded bonus should be undertaken to aid the smaller, independent, producers. For example, a bonus-variable royalty system under which the total bonus (plus accrued interest) would be paid on a schedule of annual payments out of sales receipts after the property is on stream would virtually eliminate the producers' flow-of-funds problem for financing property acquisitions. (If the property was abandoned before the total bonus bid was paid off, the producer would be liable for the remaining sum.)

40. MER is defined as the highest rate of production that can be sustained over a long period of time without reservoir damage or significant loss of ultimate oil and gas recovery. To the extent that there is a positive marginal user cost associated with any rate of flow that exceeds MER (see Davidson, "Public Policy Problems," pp. 91–94), a subsidy may have to be paid on oil produced *in excess of* MER in new fields that are under private corporate management. If the expected gain to the consuming nations in breaking the OPEC cartel and receiving their oil at a price closer to real resource costs exceeds this subsidy, such a policy would be desirable.

Some petroleum engineers claim that free (that is, not injected) gas saturation, which is created by fast production rates, actually enhances ultimate recovery from water-drive or water-flood mechanisms so that no case can be made for a loss of oil caused by production rates above MER. See Rose, "Our Vast, Hidden Oil Resources," pp. 106, 182.

ower, is to be independently supplied in the foreseeable future. Once any PEC member appreciates this eventuality, the cartel will begin to disitegrate and the increased production flow from indigenous fields competing with OPEC will tend to reduce monopoly power and increase supply.

POLICY CONCLUSIONS

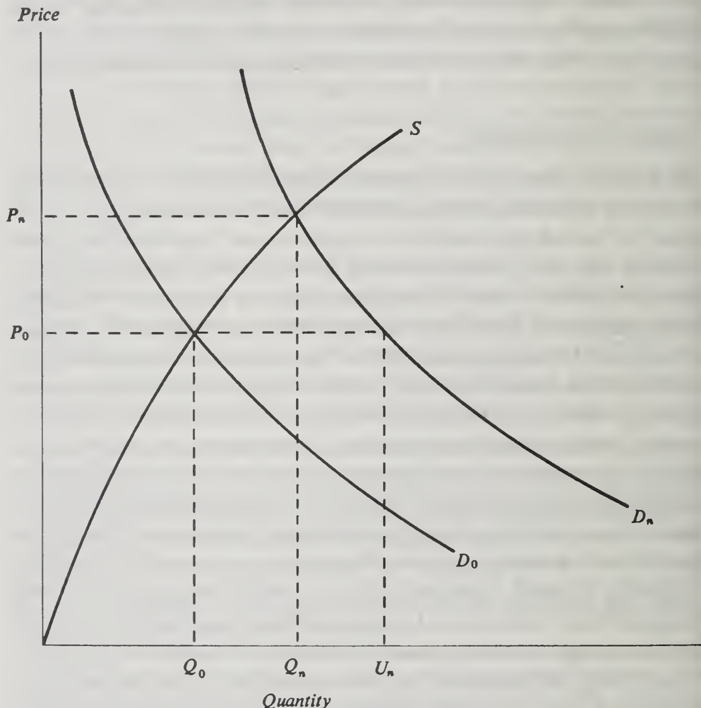
In sum, the adoption by consuming nations of policies that promise to prce down net demand prices for OPEC oil in the foreseeable future, but ppear to permit host nations to capture some large monopoly rents urrently, can have beneficial results for consuming nations. They will nleash economic forces that will encourage the break-up of the OPEC artel, spur current production, and exert downward pressure on estimates f user cost. An essential condition for the success of this approach is the xistence of an alternative energy source whose suppliers have no vested iterest in maintaining the value of OPEC or other oil reserves. Thus, for xample, if the development of the shale oil industry or the operation of the idigenous petroleum or coal industries in the United States is entrusted to onglomerate energy companies that have producing interests in OPEC or ther oil reserves, the success of any attempt to provide a substitute, competitively priced, energy source will be seriously jeopardized. Accordingly, vigorous domestic antitrust policy to dissolve conglomerate "energy ompanies" into independent domestic and foreign companies dealing with nly one energy resource is an essential element in a national energy policy.

Any policy that is expected to reduce monopoly power in the product arket over time will create negative user costs and accelerate current roduction and hence ease the energy crisis. Thus vigorous antitrust olicies and consuming-government regulation of, or participation in, the perations of producing companies can, alone or in combination, force the roducers to accept a more competitive return on their investment, and iereby eliminate monopoly rents and provide consumers with fuels at wer prices.

Market Price for Self-Sufficiency in Oil in 1980

This section presents estimates of the long-run market-clearing prices or oil that would be consistent with U.S. self-sufficiency in 1980.

Figure 1. U.S. Supply and Demand for Crude Oil, 1971 and 1980[a]



Source: See text for detailed explanation.

a. D, P, Q = demand, price, and U.S. production, respectively
0, n = subscripts indicating 1971 and 1980, respectively
U_n = U.S. demand in 1980 at 1971 price
S = long-run supply.

Figure 1 represents the basic model. Given the degree of monopoly in the petroleum industry, the curve S represents the supply path for crude oil for the United States in the long run (where user costs are zero);[41] D_0 is the U.S. demand curve for oil net of imports in the base period, 1971.

41. In what follows we use the phrase "long-run supply path" merely to denote a supply curve in which user costs are zero and the only components of the flow-supply price are Keynes' prime and supplementary factor costs including any historical monopoly rents. (See Keynes, *General Theory*, pp. 23–24, 67–68.) Our long-run supply price associated with production flows includes all factor payments to labor and capital

Accordingly, Q_0 is U.S. production in the base period, P_0 is the domestic crude price in the base period, U.S. consumption would be Q_0 plus imports (M_0) in the base period, and U_n represents the estimated total quantity of crude oil that would be demanded in the United States in 1980, at the base period price. This quantity lies on the 1980 total U.S. demand curve, D_n, which is assumed to have the same (constant) price elasticity as the base-period demand curve, D_0. Hence, in Figure 1, P_n represents the 1980 market-clearing price for full self-sufficiency—that is, meeting all U.S. demand for crude oil from U.S. production, Q_n.

We have explored three variations on this basic model. They assume (1) that some given quantity of imports from what we term "friendly" oil-producing nations, such as Canada and Venezuela, will be available to meet some part of U.S. demand in 1980; (2) that other energy sources will become more important relative to oil in supplying U.S. needs in 1980; and (3) that the degree of monopoly in the crude oil-producing industry will be zero—that is, market price will just equal long-run marginal factor costs. In applying the basic long-run supply model, we assume that the time between now and 1980 is sufficient to obtain the increased production associated with Q_n on our long-run supply path. In the final section below, we suggest why we think that, given proper governmental actions, there is no technical constraint on achieving the necessary adjustment in production by 1980.

The following sections present the formal analysis of the calculations made and the data base used for the empirical estimates of prices and production quantities underlying self-sufficiency in 1980. Included is an analysis of the sensitivity of our 1980 price estimates to reasonable variations in the elasticities of supply and demand to price.

THE ANALYTICAL MODELS

Full self-sufficiency. Assuming constant price elasticities for both supply and demand, the supply equation is specified as $Q = aP^b$, where b is the

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(including finding and development costs). Consequently, at any point of time the supply prices of remaining reserves exceed zero only to the extent that they embody capitalized past finding and developing costs that have not yet been paid for out of sales revenues. In adopting this view we are emphasizing the important economic difference between finding what exists and creating something new. Nature, not man, produced mineral deposits and Nature's long-run supply price is zero. In the long run only finding, developing, and producing costs must be paid for.

long-run supply price elasticity and a is an arbitrary constant; and the demand equation is $Q = \alpha P^{-\beta}$, where β is the constant price elasticity of demand and α is an arbitrary constant.[42] Then the equilibrium price is the one that satisfies the condition $aP^b = \alpha P^{-\beta}$. The 1980 market-clearing price, P_n, as shown in Figure 1, is computed as[43]

$$P_n = e^{\lambda}, \tag{1}$$

where

$$\lambda = \frac{\ln U_n - \ln Q_0 + (b + \beta) \ln P_0}{b + \beta}. \tag{1a}$$

The quantity produced in 1980, Q_n in Figure 1, is obtained by substituting equation (1) into the supply equation to yield

$$Q_n = e^{\phi}, \tag{2}$$

where

$$\phi = \ln Q_0 - b \ln P_0 + b \ln P_n. \tag{2a}$$

Allowing for some imports or substitution. If imports form part of the supply in 1980, the market price will be lower than that computed under the assumption of full self-sufficiency. We have analyzed the simplest case by assuming that the ratio of imports to domestically produced crude oil will remain unchanged from the base period, so that the market-clearing price is adjusted downward by replacing Q_0 in equation (1a) with $(Q_0 + M_0)$, where M_0 is the quantity of crude oil imported from specific friendly countries during the base period:

$$P_n = e^{\theta}, \tag{3}$$

where

$$\theta = \frac{\ln U_n - \ln (Q_0 + M_0) + (b + \beta) \ln P_0}{b + \beta}. \tag{3a}$$

Similarly, if, say, indigenous coal becomes an important substitute for crude oil, then in equations (1a) and (2a), U_n is reduced by the amount of additional coal used in the nth year, and the system is then solved as in the basic case.

42. The supply equation is obtained by solving the differential equation

$$b = (dQ/dP)(P/Q),$$

where b is the constant price elasticity. A similar procedure yields the demand equation.

43. Derivation available from the authors upon request.

Zero degree of monopoly. The degree of monopoly power, m, exercised by producers in any market can be measured by $m = (P - MC)/P$, where P is product price and MC is marginal resource costs. Such a measure implies a markup over marginal costs of

$$\frac{1}{1 - m} - 1.$$

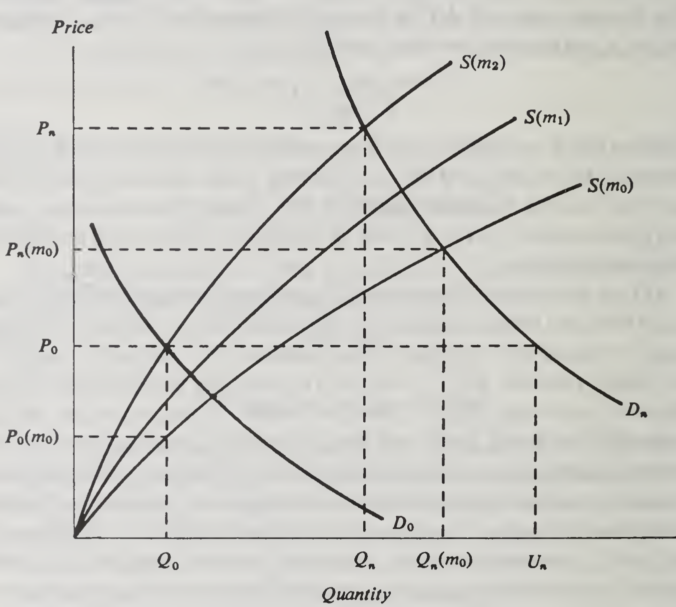
This markup is compatible with either profit maximization (in which case m is equal to the reciprocal of the price elasticity of demand at the point where price and output maximize profit) or with a conventional markup over marginal resource costs in a world of uncertainty where profit maximization may be elusive.

As long as the degree of monopoly is the same at each level of production, it can be shown that the elasticity of a supply function under an unchanging degree of monopoly[44] is equal to the elasticity of the comparable competitive supply function, MC.[45] With $S(m_x)$ representing supply under a given degree of monopoly, Figure 2 depicts a family of long-run supply paths, exemplified by $S(m_0)$, $S(m_1)$, and $S(m_2)$, where $S(m_0)$ represents the supply curve when the degree of monopoly is zero, and the others represent long-run supply paths associated with different degrees of monopoly. If in the base period the degree of monopoly was m_2, then in Figure 2 (as in Figure 1) P_0 and Q_0 represent the base price and quantity, respectively, while $P_0(m_0)$ represents the base-period price for that level of output in the total absence of monopoly. Thus, if the degree of monopoly in 1980 remains m_2, the 1980 self-sufficiency price and quantity are P_n and Q_n in Figure 2 (the same solution as in Figure 1). If, however, the degree of monopoly is reduced to zero in 1980, then by definition the 1980 self-sufficiency price would be less than P_n. In fact, under these assumptions, solution of equations (1a) and (2a) of the basic model gives 1980 prices, $P_n(m_0)$, below P_n, the 1980 self-sufficiency price of our basic model. That result provides good reason for (1) vigorous antitrust action, or (2) some form of government

44. Economic textbooks often claim that there is no supply function with monopoly in the product market; for example, see George J. Stigler, *The Theory of Price* (3rd ed., Macmillan, 1966), pp. 212–13. In fact, a supply function can be specified only when the degree of monopoly is determined—that is, the supply curve is always derived for alternative expected demand curves. It is only the assumption of a zero degree of monopoly that permits the textbooks to derive the marginal cost curve as the supply function in the purely competitive case. Given the cost function, the degree of monopoly, and entrepreneurial behavior, a supply path can always be derived.

45. A proof is available upon request from the authors.

Figure 2. U.S. Supply and Demand for Crude Oil, with Different Degrees of Monopoly, 1971 and 1980[a]



Source: See text for detailed explanation.
a. m_x = degree of monopoly (for example, m_0 represents a zero degree).
Other symbols are as defined for Figure 1.

regulation, or (3) a government corporation—or some combination of the three—to foster a reduction in the degree of monopoly in the industry.[46] We discuss these alternatives below.

Estimates of Prices, Quantities, and Elasticities for the Model

Estimation of 1980 prices and production under self-sufficiency requires data on, first, the wellhead price and U.S. production in the base period

46. Senator Adlai E. Stevenson III has suggested that a Federal Oil and Gas Corporation (FOGCO) be created to explore for, develop, and produce oil and gas on lands owned by the federal government.

(P_0 and Q_0); second, the 1980 quantity of crude oil that would be demanded at the base-year price, U_n; and third, the price elasticities of demand and supply.

BASE-PERIOD PRICE AND QUANTITY

In 1971 domestic crude oil production was near "capacity" as market-demand prorationing restrictions became less constraining. Since the end of 1971 domestic crude-oil prices have been under government controls. We have, therefore, taken the average 1971 wellhead price of $3.35 per barrel and 1971 domestic production of 9.5 million barrels per day as base-period magnitudes lying on the long-run supply path, *S*, in Figure 1.[47] In essence we are assuming (1) that statistics for the years prior to 1971 may not lie on the long-run supply path because of prorationing production restrictions; and (2) that prices and production statistics since 1971 are likely to reflect temporary government controls and positive user costs generated by the increasing strength of the OPEC cartel and the disruption of the Middle East War, so that data since 1971 are likely to lie above the long-run supply curve.

QUANTITY DEMANDED IN 1980

For the quantity of crude oil that would be demanded in 1980 at the base-period price, we have taken the projection of the National Petroleum Council. NPC estimates an increase in total domestic oil demand from 14.7 million barrels per day in 1970 (including all imports of crude and refined products) to 22.3 million barrels per day in 1980, or 4.25 percent per year.[48] To obtain net demand for crude oil from the NPC statistics, we subtracted the production of natural-gas liquids of 1.7 million barrels per day

47. Price statistics from *World Oil*, Vol. 174 (February 15, 1972), p. 21; quantity statistics from *Oil and Gas Journal*, Vol. 70 (January 31, 1972), p. 87. The latter source (p. 93) was also used for base-period import statistics from Canada and Venezuela in our model assuming imports from friendly nations.

48. National Petroleum Council, *U.S. Energy Outlook: An Initial Appraisal, 1971–1985* (1971), Vol. 2, p. 15. The projection assumed that the economic environment would remain unchanged throughout the period 1971–85. Hence it appears to be equivalent to our U_n concept.

(MMB/d) in 1970. We estimated that production of natural-gas liquids will increase by 2.2 percent a year over the decade and therefore subtracted 2.1 MMB/d from the NPC projection of total demand to obtain 20.2 MMB/d in 1980 as our estimate of U_n.

ELASTICITY ESTIMATES

Supply elasticity. Despite the intensive study of the petroleum industry by economists over the years, there is a paucity of estimates of supply elasticities for crude oil. Since this is a vertically integrated industry, reliable data on the response, at the wellhead, of supply to the market price is extremely difficult to obtain. Moreover, the technology of oil production, which involves a long gestation period between well drilling and production flows, makes it extremely difficult empirically to relate changes in market prices at given points in time with the flow-supply responses over time. Because we believe these formidable problems make direct estimate of supply elasticities of crude oil difficult, if not impossible, we attempted in an earlier paper to estimate the supply elasticity indirectly, using the theory of economic rents.[49]

49. Paul Davidson, Laurence Falk, and Hoesung Lee, "The Relations of Economic Rents and Price Incentives to Oil and Gas Supplies," in G. Brannon (ed.), *Studies in Energy Tax Policy* (Ballinger, 1974), pp. 115–55.

Some may believe that a stock-supply elasticity of additions to reserves rather than a flow-supply elasticity of oil production is relevant. We disagree for a number of reasons.

Since proved reserves are merely "shelf inventory" for oil producers, the reserve elasticity would be a good proxy for the relevant Marshallian production-flow elasticity if it is assumed that shelf inventory is continuously maintained as a constant proportion to sales. But Project Independence is a production-flow goal and not a shelf-inventory goal, and a constant reserves-production ratio in oil is no more necessary than is an unchanging inventory-sales ratio in other economic activities; therefore, a reserve elasticity estimate is not the most relevant concept. Certainly no particular level of reserves is necessary for 1980.

Moreover, actual changes in the ratio of reserves to production flows will reflect (1) changes in the interest rate; (2) changes in user cost; (3) the technological fact that additions to reserves are lumpy; and (4) changes in wellhead prices and costs. Therefore, an empirical reserve elasticity based on past data is unlikely to reflect accurately the production-flow elasticity. Finally, statistics on proved reserves as reported by the industry are more likely to be biased and unreliable than production statistics, and hence any empirical estimates of reserve elasticity are less reliable than a production-flow elasticity.

Using the "as if" methodology of positive economics,[50] then, for any given degree of monopoly, we can estimate the supply elasticity in terms of payments to landowners (economic rents) as

$$E_s = \frac{1-\alpha}{\alpha}, \tag{4}$$

where E_s is the long-run elasticity of supply and α is the proportion of the value of shipments that is paid to property owners.[51] Thus, the greater is α, the less elastic is the supply of petroleum.[52] If, for example, supply were almost perfectly elastic, payments to landowners would be insignificant, α would be negligible, and E_s would approach infinity. If, on the other hand, supply were very inelastic, payments to landowners would envelop most of the value of shipments, α would be very large, and E_s would approach zero.

Using data from the U.S. Department of the Interior on payments to property owners and the value of shipments for petroleum properties on the U.S. continental shelf, we estimated that E_s was approximately 1.4 for the years 1953–71 and 1.6 for 1971, and projected it at approximately 1.8 by 1980. Since we believe that most additional U.S. production will come from offshore properties, we prefer the 1971 base-year E_s of 1.6. In Tables 1–4, however, we also show the differences involved in using plausible estimates on either side of 1.6.

Demand elasticity. Both the income and price elasticities of demand are relevant to our 1980 estimates of demand. The NPC projection involved a 4.25 percent annual growth in demand (at the base-period price) in conjunction with a 3.9 percent annual growth in GNP. Thus the NPC forecast, which we used, implicitly assumed an income elasticity of 1.1.

50. For a discussion of this approach see Milton Friedman, *Essays in Positive Economics* (University of Chicago Press, 1953; fifth impression, 1966), Pt. 1.

51. For any given property at any given time the marginal cost schedule of annual production flows might be expected to shift upward over time (unless offset by productivity gains). Since each producer considers these expectations of changing costs and productivity gains over the life of the property when he enters into a lease contract, α will reflect them. Hence our supply elasticity reflects the expected "average" elasticity of the marginal costs of production flows over the life of each property. While the "average" elasticity in the aggregate can change over time, it is not likely to change drastically over a decade, since it is tied to the average life of properties, which normally exceeds two decades.

52. In "Relations of Economic Rents," we discuss at length some of the limitations of this measure. Nevertheless, we believe that this approach does provide a "ballpark" supply estimate for others to discuss or even shoot at.

Studies of the price elasticity of demand (E_d) have usually suggested a value in the inelastic range. The Cabinet Task Force used an estimate of 0.1, which Standard Oil Company (N.J.) provided, but its report gave no documentary support for this elasticity.[53] A study by Burrows and Domencich reported a higher, but still inelastic, price elasticity of 0.5.[54] In most of the following discussion of our estimates of the price and production outcomes in 1980, we use $E_s = 1.6$ and $E_d = 0.5$ as, in our view, the most reasonable values.

Empirical Results

The results of our analysis are summarized in Tables 1 through 4. All prices in the tables are expressed in terms of 1974 dollars: hence, the wellhead price in the 1971 base period in 1974 dollars is \$3.74—compared with the actual 1971 price of \$3.35.[55] All quantities are reported in millions of barrels per day.

Table 1 summarizes the market-clearing prices and quantities for full self-sufficiency in 1980—that is, no reliance on imports—at various elasticities. Taking 1.6 and 0.5 as the most reasonable elasticities for supply and demand, respectively, the market-clearing price would be \$5.36 (in 1974 dollars) and the quantity supplied would be 16.9 MMB/d. If E_s was as low as 1.4 and E_d was as low as 0.1, the price at full self-sufficiency, given the degree of monopoly, might be as high as \$6.19 per barrel, while 19.2 MMB/d would be produced. Table 1 also presents price and production estimates for other elasticities.[56]

53. Cabinet Task Force on Oil Import Control, *The Oil Import Question*, A Report on the Relationship of Oil Imports to the National Security (U.S. Government Printing Office, 1970), p. 226.

54. See James C. Burrows and Thomas A. Domencich, *An Analysis of the United States Oil Import Quota* (Heath-Lexington, 1970), pp. 106, 119–29. The negative signs of E_d are omitted throughout.

55. The price adjustment is made by first removing the fuel-price component from the GNP implicit price deflator for both periods, and then extrapolating the 1971 wellhead price to 1974 dollars, in proportion to the change in corrected GNP deflators between the two periods.

56. Spann and his associates have estimated a supply elasticity of 0.9, which is reflected in the first row of the table. Since their model utilizes a Cobb-Douglas function with production as the dependent variable, it can be shown that their supply-elasticity formula is comparable to ours. According to note 17 of their paper (p. 1320), the sum of

Table 1. Estimates of Market Price and Quantity for Full U.S. Self-Sufficiency in Oil in 1980, by Selected Elasticities

Prices in 1974 dollars; quantities in millions of barrels per day

	Elasticity of demand							
	0.08		*0.1*		*0.5*[a]		*1.0*	
Elasticity of supply	*Price*	*Quantity*	*Price*	*Quantity*	*Price*	*Quantity*	*Price*	*Quantity*
0.9	8.08	19.0	7.96	18.7	6.42	15.4	5.57	13.6
1.4	6.23	19.4	6.19	19.2	5.57	16.6	5.13	14.8
1.6[a]	5.87	19.5	5.84	19.3	5.36	16.9	5.00	15.1
1.8	5.59	19.6	5.57	19.4	5.20	17.1	4.90	15.4
2.0	5.38	19.6	5.36	19.5	5.06	17.4	4.81	15.7

Sources: Authors' model discussed in the text, where the sources of the basic data are also given.
a. Authors' preferred estimate.

Figure 3 can be used to interpret the results in Table 1. The S curve is the long-run supply path; D_0, D_c, and D_n are the demand curves in the 1971 base period, the current period, and 1980, respectively; P_0 is the 1971 price of \$3.74; Q_0 is the 1971 production of 9.5 MMB/d; and U_n is the demand projection for 1980 of 20.2 MMB/d. The current (January 1974) wellhead price, P_c, is \$6.63 and the (almost) vertical S_c line represents the current *short-run* supply curve, with Q_c being 1974 U.S. production of 9.2 MMB/d. (The fact that Q_c is less than Q_0 is compatible with short-run positive user costs in the current period.)

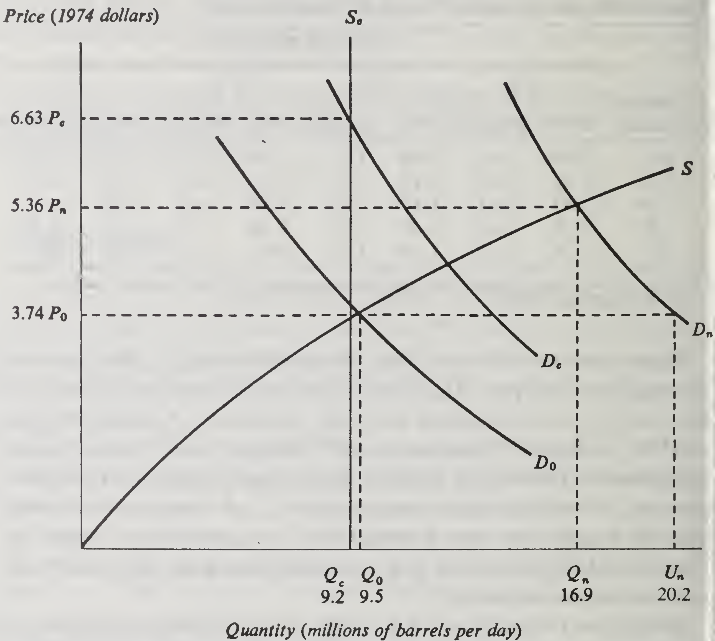
Using $E_s = 1.6$ and $E_d = 0.5$, the 1980 market-clearing price is given by the intersection of the S and D_n curves as P_n (\$5.36), while 1980 production is Q_n (16.9 MMB/d).

After we had completed our calculations, a study group at MIT published an estimate for the market price for self-sufficiency in 1980.[57] Using a mixture of econometric and judgmental models (including the NPC forecasts), they concluded that "the price of energy would be from \$10.00 to \$12.00 per barrel if supplies were limited to those within the United

their $\alpha + \beta$ equals one minus the rent share, and hence their supply-elasticity formula, which is $(\alpha + \beta)/(1 - \alpha - \beta)$, is identical with our equation (4). See Robert M. Spann, Edward W. Erickson, and Stephen W. Millsaps, "Percentage Depletion and the Price and Output of Domestic Crude Oil," in *General Tax Reform*, Panel Discussion before the House Committee on Ways and Means, 93 Cong. 1 sess. (1973), Pt. 9, pp. 1318–20.

57. The Policy Study Group of the M.I.T. Energy Laboratory, "Energy Self-Sufficiency: An Economic Evaluation," *Technology Review*, Vol. 76 (May 1974), pp. 23–58.

Figure 3. U.S. Supply and Demand for Crude Oil, Model Results, 1971, 1974, and 1980[a]



Source: Interpreted from Table 1. See text for detailed explanation.
a. c = subscript indicating 1974 current period. Other symbols are as defined for Figure 1.

States."[58] The MIT study differs from ours in that the authors attempted merely to find the price at which total demand and total supply for all fossil fuels and nuclear sources combined were in balance in 1980, whereas we have calculated the price for balancing demand and supply for oil separately. Nevertheless, the MIT results on price appear to be much higher than ours. If the two studies are compared on a common base (such as our simple model of Figure 1), the difference is readily explained.

The MIT group used the Erickson-Spann estimate of supply elasticity of 0.9 and the Hudson-Jorgenson estimate of demand elasticity of 0.15 as a

58. Ibid., p. 28.

basis for the \$10.00 to \$12.00 estimate of P_n (in Figure 1). Plugging these elasticity estimates into our model and solving for P_0—the long-run supply price in 1971 that would be consistent with this range for the self-sufficiency price in 1980—we estimate that the MIT group is implicitly assuming a 1971 price of between \$5.10 and \$6.30 (in 1974 dollars). We think this range for implicit base-period prices is much too high, and we suspect that the MIT group either let the short-run 1973 price of \$5.49 (which was dominated by user cost) color their views or assumed that speculative withholdings will continue to be profitable in 1980 because of the lack of appropriate government policy.[59] Table 1 indicates that if \$3.74 is a more appropriate estimate of the long-run supply price in the base period, the MIT elasticities suggest a price of under \$8.00 for self-sufficiency in 1980.

The effect on market price and quantity of allowing for imports of crude oil from Canada and Venezuela (in the same proportion to total U.S. production as in the base period) is shown in Table 2. Given our preferred elasticities, the 1980 price would be \$5.11 per barrel. If supply elasticity were as low as 1.4 and demand elasticity as low as 0.1, the projected price would rise to \$5.79 per barrel. A comparison of Tables 1 and 2 suggests that the importation of Canadian and Venezuelan oil is likely to reduce the market-clearing price by approximately 4.7 percent and domestic production by approximately 7.7 percent. Thus, it appears that imports from friendly foreign sources are not likely to lower the price of "Project Independence" dramatically.

Table 3 displays estimates of the market price for self-sufficiency if no monopoly at all existed in the oil industry—in other words, if price were just equal to long-run marginal resource cost. To estimate the zero-monopoly price in the base period, we took Nordhaus' estimate of "the competitive supply price for domestic petroleum"[60] of \$2.33 in 1970, and

59. Another possibility is that the MIT group implicitly assumed that long-run real marginal factor costs for any given production flow will increase over time from 36 to 68 percent more than producers' historical expectations of cost changes as reflected in α. (This possibility was implied in some comments by Charles L. Shultze, in which he argued that increasing marginal cost over time is a special characteristic of depletable natural resources. Although this may be a characteristic for any given property at any point of time, as note 51 indicates, we do not believe it is a necessary characteristic of the aggregate of producing properties considered over time.) The 1973 price of \$5.49 is the midyear weighted average of prices for "new" and "old" crude oil, calculated from *World Oil*, Vol. 178 (February 15, 1974), p. 73.

60. Nordhaus, "Allocation of Energy Resources," p. 557. Nordhaus notes that this price is the "long-run competitive supply price."

Table 2. Estimates of Market Price and Quantity of Crude Oil for the United States in 1980, Allowing for Imports from Canada and Venezuela, by Selected Elasticities

Prices in 1974 dollars; quantities in millions of barrels per day

	Elasticity of demand							
	0.08		*0.1*		*0.5*[a]		*1.0*	
Elasticity of supply	*Price*	*Quantity*	*Price*	*Quantity*	*Price*	*Quantity*	*Price*	*Quantity*
0.9	7.30	17.3	7.20	17.1	5.97	14.5	5.28	13.0
1.4	5.83	17.6	5.79	17.5	5.28	15.4	4.92	13.9
1.6[a]	5.53	17.7	5.50	17.6	5.11	15.6	4.82	14.2
1.8	5.30	17.8	5.28	17.7	4.98	15.9	4.73	14.5
2.0	5.13	17.8	5.11	17.7	4.86	16.0	4.66	14.7

Sources: Same as Table 1.
a. Authors' preferred estimate.

Table 3. Estimates of Market Price and Quantity of Crude Oil for U.S. Full Self-Sufficiency in 1980, Assuming Perfect Competition, by Selected Elasticities

Prices in 1974 dollars; quantities in millions of barrels per day

	Elasticity of demand							
	0.08		*0.1*		*0.5*[a]		*1.0*	
Elasticity of supply	*Price*	*Quantity*	*Price*	*Quantity*	*Price*	*Quantity*	*Price*	*Quantity*
0.9	5.87	19.5	5.82	19.3	5.13	17.3	4.72	16.0
1.4	4.48	19.9	4.47	19.8	4.31	18.8	4.18	18.1
1.6[a]	4.21	20.0	4.21	20.0	4.11	19.3	4.04	18.7
1.8	4.01	20.1	4.00	20.1	3.96	19.7	3.92	19.3
2.0	3.85	20.2	3.85	20.1	3.83	20.0	3.82	19.8

Sources: Same as Table 1.
a. Authors' preferred estimate.

converted it first into our zero-monopoly, 1971 base-period price by increasing it in proportion to the actual change in wellhead prices between the two years, and then into 1974 dollars by the procedure used to construct the base price underlying Table 1.

The estimated zero-monopoly price for full self-sufficiency in 1980 is \$4.11 (assuming $E_s = 1.6$ and $E_d = 0.5$), only 9.9 percent higher than the 1971 base-period monopoly price and dramatically lower than current

Table 4. Estimates of Market Price and Quantity of Crude Oil for Full U.S. Self-Sufficiency in 1980, Assuming Increased Substitution of Coal for Oil

Prices in 1974 dollars; quantities in millions of barrels per day

	Elasticity of demand							
	0.08		*0.1*		*0.5*[a]		*1.0*	
Elasticity of supply	*Price*	*Quantity*	*Price*	*Quantity*	*Price*	*Quantity*	*Price*	*Quantity*
0.9	6.13	14.8	6.07	14.7	5.29	13.0	4.83	11.9
1.4	5.19	15.0	5.17	14.9	4.83	13.6	4.58	12.6
1.6[a]	4.99	15.1	4.97	15.0	4.71	13.7	4.51	12.8
1.8	4.84	15.1	4.83	15.0	4.62	13.9	4.45	13.0
2.0	4.72	15.1	4.71	15.1	4.54	14.0	4.40	13.1

Sources: Same as Table 1.
a. Authors' preferred estimate.

prices. Hence, if antitrust or other governmental policies markedly reduced the degree of monopoly in the domestic crude-oil industry, self-sufficiency in 1980 would be achievable *and* compatible with lower costs than consumers are currently paying. In other words, even in the absence of cheaper Middle Eastern oil, the age of cheap energy for U.S. consumers need not be over.[61]

Table 4 estimates the effects of increased substitution of coal for crude oil on the 1980 full self-sufficiency price. Using the U.S. government's assumption[62] that coal production (in terms of millions of barrels per day oil equivalent) will be 11.0 MMB/d in 1980 and assuming that all the increase in coal production from 6.2 MMB/d in the 1971 base period will be used to replace crude oil, our estimate of the self-sufficiency price is $4.71.

61. Even for the most inelastic case in Table 3, the self-sufficiency price of $5.87 is much lower than the current $6.63 wellhead price, indicating substantial potential benefits to consumers of policies aimed at reducing monopoly markups in the domestic oil industry.

62. See "Project Independence Background Paper" (prepared for the Washington Energy Conference, February 1974; processed), pp. 13–14. The Office of Coal of the Federal Energy Administration has since revised its estimates to include three assumptions concerning coal production in 1980: business as usual—892 million tons; business accelerated—1,376 million tons; most likely—950 million tons. The last assumption is similar to the office's initial estimate of 962 million tons of coal per year, which converts to 11.0 million barrels of oil-equivalent a day.

SUMMARY

In sum, if the degree of monopoly in the domestic oil industry in 1980 is the same as it was in 1971, and if the government adopts policies that assure that the user cost inherent in crude oil is zero, then the 1980 long-run price for U.S. self-sufficiency will be $5.36 (in 1974 dollars) and U.S. production will be 16.9 MMB/d. If imports from friendly nations such as Canada and Venezuela occur in the same proportion to U.S. production as they did in 1971, then the price in 1980 will be $5.11. If, on the other hand, coal is increasingly substituted for crude oil, we estimate the 1980 self-sufficiency wellhead price will be $4.71. All of these estimates assume our preferred elasticities of supply (1.6) and demand (0.5). Since the January 1974 average wellhead price of domestic crude was $6.63, these estimates imply a decrease of between 19.2 percent and 29.0 percent in crude prices in the next few years. In other words, if speculative expectations can be stifled and the degree of monopoly kept at its 1971 level, self-sufficiency can be achieved at lower real costs to the consumers.

Moreover, if monopoly power could be eliminated by antitrust action, government regulation, the formation of a federally sponsored corporation to provide a competitive yardstick, or some combination of the three, then, as Table 3 indicates, the 1980 full self-sufficiency price is most likely to be $4.11—a decline of 38.0 percent from the January 1974 price of crude. Even in the most pessimistic (and unlikely) inelastic case presented in Table 3, the 1980 zero-monopoly price would be $5.87, or approximately 11.5 percent less than the 1974 price and only 57.0 percent higher than the base-period price. Thus, any policy that substantially reduces the degree of monopoly in the domestic oil industry could offer dramatic savings to consumers.

Of course, all empirical results assume that domestic production in 1980 involves zero user costs—that producers do not withhold production in order to garner higher profits in the future. This situation may occur fortuitously in 1980 if at that time entrepreneurs' views of the future happen to agree that withholding production is not profitable. On the other hand, such an outcome is by no means inevitable; accordingly, the U.S. government may need specific policies that assure it. These may involve (1) government regulation of wellhead price with the unalterable proviso that permitted price increases *must* be phased in at an annual rate

that is lower than current and expected rates of interest (so that discounted profits due to the price increase are negative), or (2) taxes on capital gains on oil reserves and windfall profits on production at rates in excess of 100 percent, or (3) both.[63] Such policies, operating in tandem with the breaking up of conglomerate energy corporations into independent individual production units advocated in the first half of this paper, will go a long way toward preventing positive user costs and their adverse impact on the production of energy resources at home and abroad.

Finally, and most important, the reader is cautioned that the objective of the second half of this paper has been to provide a range of crude oil prices in 1980. If the U.S. government actively pursues the policies we advocate, we expect the 1980 wellhead price of crude oil in the United States to range between $5 and $7 (in 1974 dollars) rather than between $10 and $12, as others have suggested. On the other hand, if the government permits a free market price for oil without altering existing conditions, the 1980 price for self-sufficiency could easily be even higher than $12 as the user-cost estimates of domestic producers encourage them to act as willing but silent partners in the OPEC cartel. In that case, domestic oil prices will in essence be set by the sheiks on the Persian Gulf, for we see no reason to believe that the OPEC cartel will unravel of its own accord.

A FINAL CAVEAT

The $5.36 price estimated for the self-sufficiency situation in 1980 involves an increase in annual production of crude oil of more than 75 percent from current levels. Aside from positive user costs, two factors may limit the ability and willingness of the industry to expand by 1980 along the long-run supply path embodying a constant degree of monopoly.

First, the implied increase in exploration activities between 1974 and 1980 may be unachievable at reasonably stable input prices, as bottlenecks develop in the input markets: shortages may occur in drilling rigs, or in the supply of geologist teams, or in the funds necessary for expansion.

In this connection, however, statistics show that the number of shut-in oil-producible zones on the U.S. outer continental shelf jumped from 14.3

63. Other policies could achieve the same objective—government-held buffer stocks that could be dumped if the price begins to rise, for one example. Once the principle of zero user costs is recognized and accepted, economists should be able to conceive of many alternative policies.

percent of the total completions of producible oil zones in 1971 to 44.4 percent in 1972 and 44.5 percent in 1973,[64] while the number of completed wells continued to grow by some 300 per year from 5,718 in 1971 to 6,421 in 1973. This tremendous increase in readily available, but unused, productive capacity is compatible with the sudden appearance of large positive user costs in 1971 as OPEC actions began to escalate oil prices worldwide. Nevertheless, these shut-ins mean significant additional capacity already in place, and the remaining exploration and development costs necessary to achieve self-sufficiency by 1980 are thus significantly lower (and hence bottlenecks are less threatening) than the inferences of a simple comparison of estimated 1980 output with current production.[65]

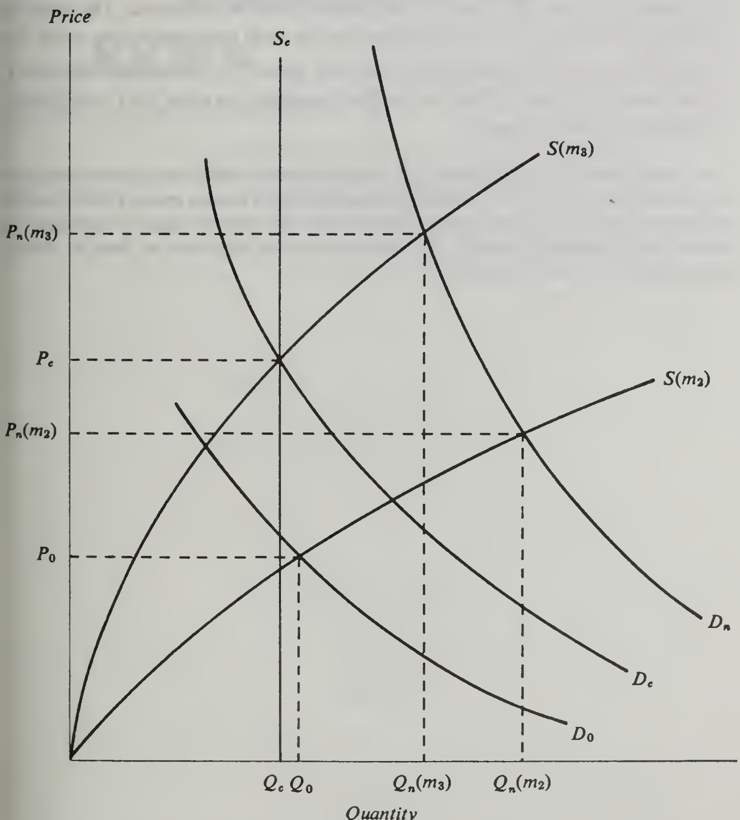
Moreover, to the extent that the government alters its leasing policy from front-loaded bonus contracts with fixed-percentage royalty to a bonus system to be paid out of sales revenues (as explained in note 39), financial constraints will be significantly reduced because a major portion of the investment costs (for land) can be financed out of sales receipts.

Second, current (January 1974) prices of \$6.63 per barrel provide huge windfall profits over long-run marginal factor costs, and hence at least temporarily there has been a tremendous increase in profit markups and therefore in the degree of monopoly since the 1971 base period. If producers (and buyers) come to accept the current higher degree of monopoly as a permanent characteristic of the industry, the relevant long-run supply will shift upwards and the market-clearing self-sufficiency price will be higher and production lower than our preferred estimate. Figure 4 shows, for example, the long-run supply curve $S(m_2)$ for the degree of monopoly in the base period. Here, D_0, D_c, and D_n represent the demand curves in the base period, current period, and 1980, respectively; P_0, Q_0, and $P_n(m_2)$, $Q_n(m_2)$ are the price and production levels for the base period and for 1980, respectively. The current levels of price and production, which are represented by P_c and Q_c, lie on the short-run, almost vertical, supply curve, S_c, *and* on a long-run supply curve, $S(m_3)$, which represents a higher degree of monopoly (m_3) than obtained in the base period. If m_3 should

64. U.S. Geological Survey, *Outer Continental Shelf Statistics* (1974), p. 34. In 1965, for example, the ratio of shut-ins was 18 percent, and the trend was steadily downward until 1972.

65. If the United States had such a large percentage of its total productive facilities shut down, does anyone doubt that GNP could be increased by 75 percent by 1980 without severe bottlenecks?

Figure 4. U.S. Supply and Demand for Crude Oil, Assuming the 1974 Degree of Monopoly Becomes Permanent[a]



Source: See text for detailed explanation.
a. m_2 and m_3 = the 1971 and new, higher, 1974 degrees of monopoly, respectively. Other symbols are as defined for Figure 1.

persist through 1980, then the self-sufficiency price will be $P_n(m_3)$—which is higher than $P_n(m_2)$—and production will be $Q_n(m_3)$—which is lower than $Q_n(m_2)$. All of our self-sufficiency estimates are based on the assumption that no disruptive bottlenecks will occur and that monopoly will not intensify. Obviously, if these factors become important as 1980 approaches,

the government will have to develop policies to counteract them. Merely setting the goal of self-sufficiency, although desirable from the consumer's standpoint in a cartelized world oil market, is not sufficient. The need is for supportive policies to bring prices in line with long-run factor costs by reducing, or at least containing, monopoly power; to discourage inventory speculation by reducing the user cost of crude oil to zero; and to alleviate bottlenecks if they occur.[66]

66. For example, bottlenecks may call for government allocations of scarce resources (at constant factor prices), or redefining self-sufficiency to include imports from friendly nations, or delay in achieving self-sufficiency. Since the current degree of monopoly is higher than historically normal, the government must take steps at least to reduce monopoly power to its former level.

ROBERT R. NATHAN TESTIMONY BEFORE THE SENATE INTERIOR COMMITTEE, APRIL 28, 1975

RRNA

ROBERT R. NATHAN ASSOCIATES, INC.

1200 EIGHTEENTH STREET N W WASHINGTON D C 20036
PHONE 202/833-2200 TELEX 248482 CABLE NATECON

TESTIMONY OF ROBERT R. NATHAN
ON PETROLEUM PRICING
BEFORE THE SENATE COMMITTEE
ON THE INTERIOR

April 28, 1975

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RRNA

ROBERT R. NATHAN ASSOCIATES, INC.

1200 EIGHTEENTH STREET N.W. WASHINGTON D.C. 20036
PHONE 202/833-2200 TELEX 248482 CABLE NATECON

THE COST OF FINDING, DEVELOPING, AND PRODUCING CRUDE OIL IN THE UNITED STATES

Much attention has been given to the substantial increases in the price of crude oil since the embargo some 18 months ago. The focus has been on prices of both imported supplies and domestic supplies. Strong concern has been manifested about the impact of oil prices on consumers and also the inflationary aspects of the sharply higher prices. Much less attention has been focused on supply considerations.

For a few years the price of oil in the United States was held down by prospects of low cost imports. Data clearly indicate that petroleum could be imported at far less than new production costs in the United States. This resulted in increased dependence on imports and less reliance on new resources explored and exploited in the U.S. The marked decline over the years in exploratory drilling appears clearly to have been the result of low prices that did not cover economic costs. The low prices were attributable to costs of imported petroleum and the price control threat inherent in the Oil Import Program.

In order to shed light on the price problem for new domestic oil, we have undertaken an analysis of the true economic costs involved in all aspects of new production of crude oil in this country. The results are both significant and provocative. It is quite clear that for some time oil prices in the United States

RRNA

have been at levels well below actual costs and this has had a discouraging impact on finding and developing new sources of oil supplies. These findings may not be good news for us, but it is essential that the facts be developed and aired in order to arrive at policies which will be compatible with moving toward the fulfillment of our national objectives of reducing our dependence on insecure sources for energy and reducing the unfavorable balance of payments resulting from heavy imports of crude oil and petroleum products. Simultaneously, we must take into account the longer run needs of consumers and the problems of general inflation.

The following observations relate specifically to the cost and price problems of new oil development in the United States and should help to shed light on a complex and sensitive subject. It should be noted that these problems are quite distinct from two other issues that must be addressed by overall energy policy; the problem of conservation by constraining demand; and the problem of preventing or offsetting unintended enrichment of producers of old oil or impoverishment of consumers. Here we are dealing only with incentives and means to add to domestic supplies.

Unless oil can be sold by producers at prices sufficient to cover costs plus a return on the operator's capital investment sufficient to sustain exploration, then surely wildcat drilling in the United States will decline. It is the rate of return on capital investment that provides the driving force to sustain the level of exploratory activity. This, in turn, determines the level of our oil discoveries and production

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volume. It is in this context that we must take note of the huge cost increases that have been experienced in finding, developing, and producing crude petroleum.

The attached table, Exhibit I, provides data on the economic cost of finding, developing and producing crude oil in the United States for each year during the period 1959 through 1974. The oil (and related gas) reserves found each year represent the total quantity of usable reserves that are available for production attributable to all new wells drilled within that year. The total level of capital investment in drillings each year in the United States (excluding Prudhoe Bay) is also shown. Revenues from the sale of each year's discovered reserves of oil and their attendant costs were projected year by year over the calculated life of the reserve. The price at which each year's discovered oil was assumed to be sold over the life of the reserve was then determined to be at that level which would yield a discounted cash flow rate of return to the producer of 15 percent after payment of all costs, including income taxes. This is referred to as the "economic price," in that it represents the price necessary to induce wildcat producers to take the risks and incur the costs attendant on finding and developing new sources of crude oil.

In the calculations, all costs incurred in the drilling of dry wells as well as new discoveries have been taken into account. All tax incentives, such as intangible drilling costs and percentage depletion, as they actually existed in each year have been added to cash flow in arriving at the price needed to yield the 15 percent rate of return. The 1974 calculated price does not, therefore, reflect the increased costs and reduced

capital accumulation which will result from the changes in percentage depletion rates and the 65 percent taxable income ceiling enacted in 1975. It does not take into account the 10 percent minimum preference tax on percentage depletion or the higher than 50 percent income tax bracket of many individual entrepreneurs.

An enterprise engaged in oil exploration is distinctly unique from most other kinds of business. It utilizes depleting capital as income and then expends the larger part of this income in ventures, many of which result in a negative return. Four out of five exploratory wells drilled are dry. A 15 percent return on invested capital must be regarded as an extremely conservative base for calculating the economic price in an industry that is so speculative and risk-laden.

The year by year economic price and the actual price received for oil discovered over the 1959-74 period are shown graphically in Exhibit II. As is evident, only in 1959 did the price actually received equal or exceed the economic price for new crude oil. The consequences of this price situation should have been anticipated. During this 1959-74 period the number of barrels per exploratory well drilled dropped by almost 50 percent. The level of drilling activity fell by 56 percent. The number of independent oil producers declined from an estimated 20,000 to 10,000. The price chart largely explains these declines. Reasonable returns from exploratory drilling involved real costs that far exceeded the prices at which oil was being bought abroad.

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Despite the recent price increases in crude oil, the economic cost of new oil remained above the price actually received through 1974. If new oil prices were rolled back or if ceilings on new oil were set at levels below the economic cost, taking into account the cost effects of the changes already made in percentage depletion, we could well again experience the situation that resulted in the precipitous decline in the discovery of oil reserves over the past 20 years. Oil is more difficult to find than in the earlier years of the industry, but scientific techniques are increasingly sophisticated and costly. If the decline in domestic discoveries is to be reversed for any extended period of time, the existence of appropriate economic incentives -- absent for so many years -- is a necessary prerequisite for more exploration.

To the degree that exploration for new oil in the United States is discouraged, additions to reserves and domestic production will be at lower levels. This will leave the nation with the unpleasant choice of importing more oil from the Mideast and African OPEC countries or greatly reducing consumption. Reducing consumption should be pursued but it will entail sharply increased prices, sharply increased taxes, or rationing -- or some combination of these. Despite the higher costs to obtain new domestic oil, the implicit price compares favorably with the price of imported oil and yields a large bonus in the form of national security.

Approximately two-thirds of domestic crude oil is sold at the controlled price of $5.25 per barrel; the remaining one-third is not subject to price ceilings. Production of crude oil

RRN A

at uncontrolled prices comes to about 2.9 million barrels a day, accounting for some 17 percent of the total supply, including imports from abroad, needed to meet United States demand for petroleum products. The effect on consumer prices for all petroleum products that would result from lowering prices on the 17 percent share of the market accounted for by oil presently sold at market prices is clearly very limited.

The thrust of the foregoing analysis is clear. It costs a great deal more to find, develop, and produce oil today than ever in the past. If this nation is serious about reducing dependence on oil imported from insecure sources, it will have to pay sufficient prices to cover the true economic costs of exploration, discovery, development, and production.

April 22, 1975

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EXHIBIT I

COST OF NEW OIL
TOTAL UNITED STATES
YEARS 1959 THROUGH 1974

YEAR	(1) GROSS OIL RESERVES MILLIONS OF BBLS	(2) GROSS GAS RESERVES BILLIONS OF CU FT	(3) GROSS OIL & GAS SALES MILLIONS OF $	(4) ROYALTY EXPENSE MILLIONS OF $	(5) AD VALOREM & STATE TAXES MILLIONS OF $	(6) OPERATING EXPENSES MILLIONS OF $	(7) ADJUSTED GROSS INCOME MILLIONS OF $	(8) TOTAL INVESTED CAPITAL MILLIONS OF $	(9) INTANGIBLE DRILLING COST MILLIONS OF $	(10) DEPLETION ALLOWANCE MILLIONS OF $	(11) DEPRECIATION MILLIONS OF $	(12) TAXABLE INCOME MILLIONS OF $	(13) INVEST. TAX CREDIT MILLIONS OF $	(14) FEDERAL INCOME TAXES MILLIONS OF $	(15) AFTER TAX NET INCOME MILLIONS OF $	(16) NET CASH FLOW MILLIONS OF $	(17) NET CASH FLOW DISC, 15% MILLIONS OF $	(18) GROSS OIL PRICE $/BBL	(19) GAS PRICE $/THOUS. CU FT
1959	3,793	4,594	11,740	1,467	680	1,893	7,700	3,630	2,341	2,362	857	2,139	0	1,070	6,630	3,000	0	2.86	0.194
1960	2,785	3,373	10,179	1,272	594	1,505	6,807	3,150	2,042	[illegible]	706	1,972	0	986	5,821	2,671	0	3.40	0.210
1961	2,773	3,358	10,025	1,253	567	1,531	6,674	3,120	2,048	[illegible]	701	1,873	0	936	5,738	2,618	0	3.34	0.227
1962	2,511	3,041	10,174	1,272	570	1,550	6,783	3,202	2,078	2,100	704	1,900	49	901	5,882	2,680	0	3.77	0.233
1963	2,133	2,583	9,721	1,215	538	1,565	6,403	3,[illegible]95	[illegible]	2,304	713	1,607	50	753	5,650	2,555	0	4.27	0.237
1964	3,118	3,775	11,223	1,403	641	1,670	7,508	3,475	2,155	2,307	769	2,277	54	1,085	6,424	2,949	0	3.32	0.231
1965	2,234	2,705	9,098	1,137	522	1,498	5,940	2,917	1,981	1,852	693	1,414	48	659	5,282	2,365	0	3.79	0.234
1966	1,986	2,560	9,998	1,250	562	1,477	6,709	3,135	2,009	2,085	758	1,857	41	887	5,822	2,687	0	4.73	0,236
1967	1,874	1,908	9,808	1,226	569	1,426	6,587	3,132	2,088	2,042	753	1,704	43	809	5,778	2,646	0	4.99	0.240
1968	2,003	2,258	10,833	1,354	634	1,478	7,367	3,446	2,268	2,273	781	2,045	55	968	6,399	2,953	0	5.13	0.246
1969	1,522	1,901	11,146	1,333	640	1,493	7,6[illegible]	3,406	2,112	[illegible]	757	2,393	37	1,159	6,461	3,055	0	7,01	0,251
1970	1,766	2,138	13 352	1,669	770	1,667	9,247	3,590	1,891	2,123	692	4,340	0	2,170	7,077	3,487	0	7.25	0.257
1971	1,267	1,488	10,818	1,352	605	1,546	7,315	3,032	1,751	1,864	606	3,093	42	1,504	5,811	2,779	0	8.22	0.273
1972	1,303	1,764	10,105	1,263	561	1,499	6,781	2,986	1,893	1,726	696	2,467	49	1,185	5,597	2,611	0	7,36	0.293
1973	1,049	1,450	9,458	1,182	448	1,451	6,377	2,846	1,855	1,628	669	2,225	47	1,066	5,311	2,465	0	8,63	0.279
1974	1 206	1,677	16,099	2,012	762	2,137	11,187	4,612	2,739	2,813	987	4,648	69	2,255	8,932	4,300	0	12,73	0.449

NOTE: Figures are for total United States except Prudhoe Bay field in Alaska. All financial data expressed in constant dollars for year of initial projection. Columns may not add precisely because of computer rounding.

Explanatory Notes:

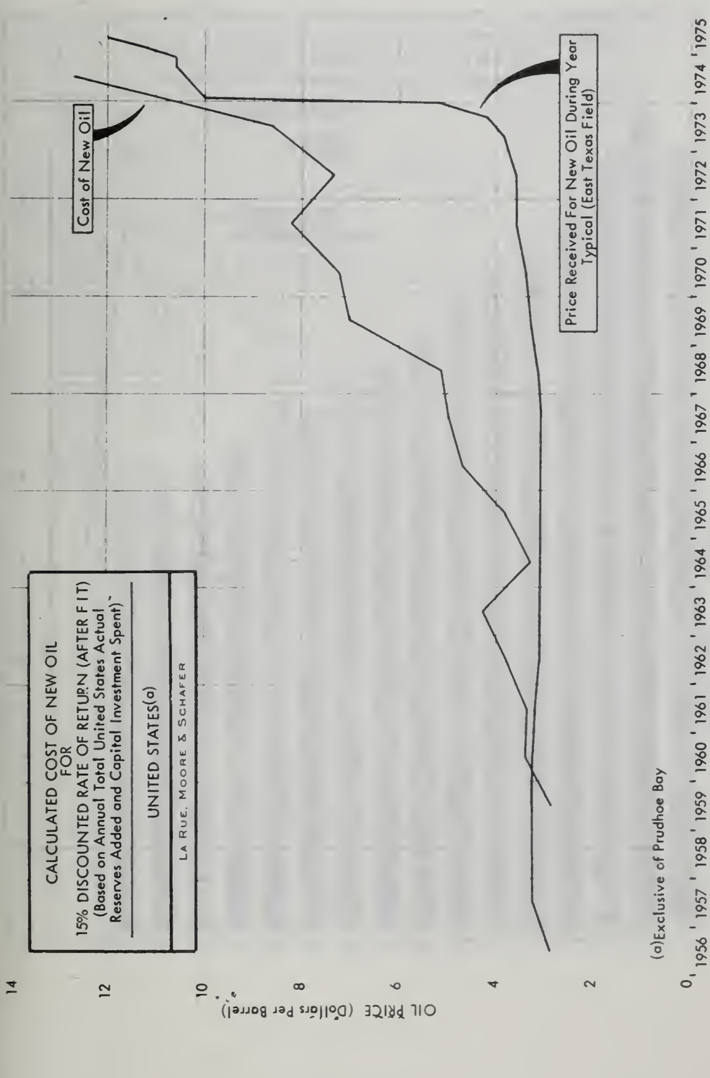
Column

(1) Oil reserves added by drilling plus expected upward revisions.
(2) Gas reserves associated with oil.
(3) Column (1) x Column (18) + Column (2) x Column (19).
(4) 1 [illegible]% of Column (3)
(5) Variable tax rate x (Column (3) - Column (4)). Tax rate is approximately 6%.
(6) Direct operating costs including field labor and supplies, maintenance, general and administrative [illegible]rhead.
(7) Column (3) Column (4) Column (5) Column (6)
(8) Total capital investment attributable to oil reserves added in year including leasehold costs.

Column

(10) Includes cost and percentage depletion based on law at time of first year projected.
(11) Cumulative depreciation of tangible drilling costs and leasehold equipment.
(12) Column (7) - Column (9) - Column (10) - Column (11).
(13) Investment tax credit is variable for each year depending on law at start of year. Zero some years.
(14) Column (12) x 50% - Column (13).
(15) Column (7) - Column (14) or alternatively Column (12) - Column (14) + Column (10) + Column (9) + Column (11).
(16) Column (15) - Column (8).
(17) Column (16) discounted at 15% per annum compounded annually. Must total zero.
(18) Gross oil price at wellhead required for 15% discounted rate of return after federal income taxes.
(19) Gross gas price for the purp[illegible] [illegible] [illegible]

EXHIBIT II


CALCULATED COST OF NEW OIL
FOR
15% DISCOUNTED RATE OF RETURN (AFTER F I T)
(Based on Annual Total United States Actual
Reserves Added and Capital Investment Spent)
UNITED STATES(a)
LA RUE, MOORE & SCHAFER
Cost of New Oil
Price Received For New Oil During Year
Typical (East Texas Field)
OIL PRICE (Dollars Per Barrel)
0
2
4
6
8
10
12
14
1956
1957
1958
1959
1960
1961
1962
1963
1964
1965
1966
1967
1968
1969
1970
1971
1972
1973
1974
1975
(a)Exclusive of Prudhoe Bay

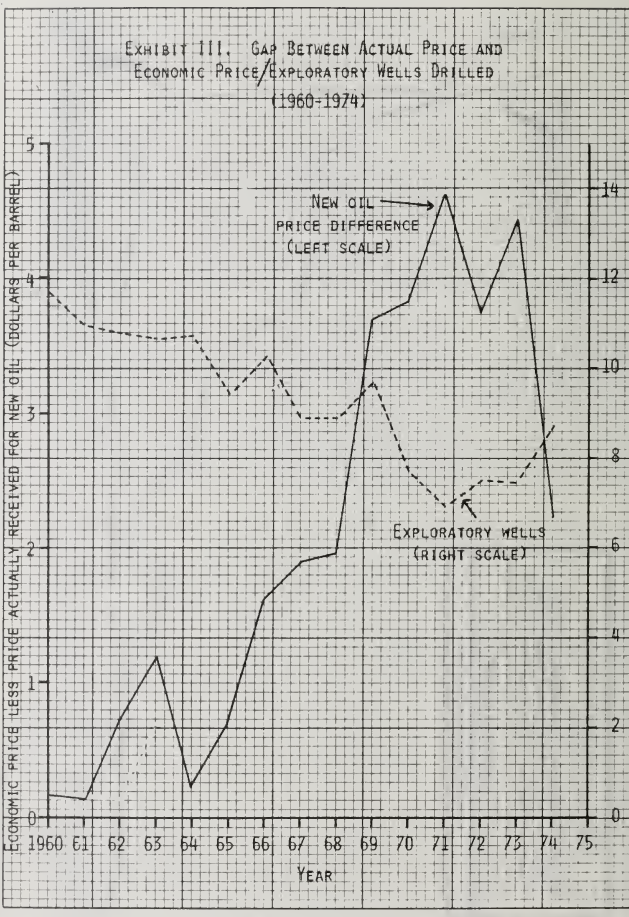


Exhibit III. Gap Between Actual Price and Economic Price/Exploratory Wells Drilled (1960-1974)
New oil price difference (left scale)
Exploratory wells (right scale)
Economic price less price actually received for new oil (dollars per barrel)
Number of exploratory wells drilled (thousands)
Year
0
1
2
3
4
5
0
2
4
6
8
10
12
14
1960
61
62
63
64
65
66
67
68
69
70
71
72
73
74
75

EXHIBIT IV. DOMESTIC PRODUCTION OF CRUDE OIL AND NATURAL GAS LIQUIDS AND IMPORTS OF CRUDE OIL AND REFINED PETROLEUM PRODUCTS: UNITED STATES 1959-1974

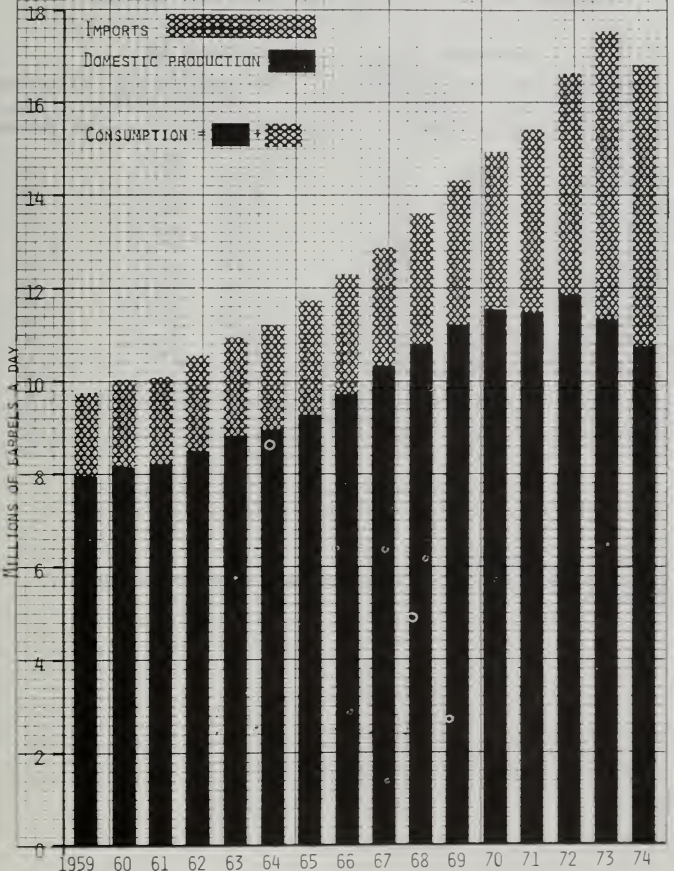


Exhibit III A.

Economic Price of New Oil and Price Received for Oil

Year	Economic Price for New Oil 1/	Price Received for Oil 2/	Difference
	($ per bbl.)	($ per bbl.)	($ per bbl.)
1959	2.86	3.25	- .39
1960	3.40	3.25	.15
1961	3.34	3.20	.14
1962	3.77	3.10	.67
1963	4.27	3.10	1.17
1964	3.32	3.10	.22
1965	3.79	3.10	.69
1966	4.73	3.11	1.62
1967	4.99	3.11	1.88
1968	5.13	3.16	1.97
1969	7.01	3.32	3.69
1970	7.25	3.40	3.85
1971	8.22	3.60	4.62
1972	7.36	3.60	3.76
1973	8.63	4.20 3/	4.43
1974	12.73	10.50 3/	2.23

1/ Col. 18, Exhibit I
2/ Price received for oil during year (East Texas Field).
3/ New oil

Exhibit IV A. Domestic Production of Crude Oil and Natural Gas Liquids and Imports of Crude Oil and Refined Petroleum Products United States 1959 - 1974

Year	U.S. Production (000 Bls/Day)	Imports into U.S. (000 Bls/Day)	U.S. Consumption (000 Bls/Day)
1959	7,969	1,780	9,749
1960	8,194	1,815	10,009
1961	8,242	1,917	10,159
1962	8,496	2,082	10,578
1963	8,838	2,123	10,961
1964	8,976	2,258	11,234
1965	9,242	2,468	11,710
1966	9,720	2,573	12,293
1967	10,339	2,537	12,876
1968	10,796	2,839	13,635
1969	11,215	3,166	14,381
1970	11,549	3,419	14,968
1971	11,523	3,926	15,449
1972	11,861	4,741	16,602
1973	11,296	6,256	17,552
1974	10,781	6,083	16,864

"CALCULATION OF NEW OIL COSTS, UNITED STATES, YEARS 1959 THROUGH 1974," MAY 1, 1975

LA RUE, MOORE & SCHAFER
PETROLEUM CONSULTANTS
SUITE 3318   2001 BRYAN TOWER
DALLAS, TEXAS 75201
214/747-7705
TELEX 73-321

CALCULATION OF NEW OIL COSTS
UNITED STATES
YEARS 1959 THROUGH 1974
MAY 1, 1975

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LA RUE, MOORE & SCHAFER
PETROLEUM CONSULTANTS
SUITE 3318 2001 BRYAN TOWER
DALLAS, TEXAS 75201
214/747-7705
TELEX 73-321

CALCULATION OF NEW OIL COSTS
UNITED STATES
YEARS 1959 THROUGH 1974
May 1, 1975

FOREWORD

Scope of Investigation

A study has been made to estimate the economic cost of finding, developing, and producing crude petroleum in the United States, exclusive of the Prudhoe Bay field in Alaska, for each year during the period from 1959 through 1974. Yearly historical additions to the United States oil reserve inventory were analyzed as were the expenditures associated with petroleum exploration and development and production. Projections of production and revenue attributable to the reserves added were processed using an economic model designed specifically for the purpose. As an aid to interpreting the significance of derived economic oil costs, various petroleum activity indicators were compiled and compared to the selling price of oil. While this study is specifically concerned with crude petroleum and its associated gas, the

techniques used are also generally applicable to natural gas exploration since many economic factors are common to both.

Authority

This study was authorized by Mr. Robert R. Nathan, President of Robert R. Nathan Associates, Inc.

Source of Information

Information used in this study was obtained from published sources which we consider to be the most reliable and complete, our own files, and work papers compiled during previous work on cost data for Project Independence. The calculations of new oil cost are consistent with those developed by the Interagency Task Force on Oil, chaired by Dr. V. E. McKelvy of the U. S. Geological Survey. Some of the more important published references may be found in Appendix A and other sources are given as footnotes on various tables and figures in this report.

SUMMARY AND CONCLUSIONS

A series of computations have been made for each of the years from 1959 through 1974 to estimate the economic cost of crude petroleum in the United States. These studies show that the economic cost of crude petroleum in the United States, exclusive of Prudhoe Bay, increased from $2.86 per barrel in 1959 to $8.70 per barrel in 1973. During the same period, the typical selling price of new oil increased from $3.25 to $4.00 per barrel.

As a consequence of the ever increasing disparity between the actual economic cost and selling prices, petroleum exploration during the period declined sharply. Between 1959 and 1973 total drilling activity dropped 50 percent, drilling rigs in service declined by 60 percent, and over 100 producers, many of substantial size, found it more attractive to sell their properties to larger international firms than to continue exploration activities.

Nationwide costs have not been compiled for 1974, but we have estimated capital expenditures based on the number of wells drilled and have calculated the economic cost of oil found in 1974 to be $12.84 per barrel. As a result of the Arab embargo, the 1974 selling price for crude oil increased to approximately $10.00 per barrel, providing great stimulus to exploratory drilling and a marked reversal in the 15-year trend of declining activity.

Economic cost is defined as the cost of finding, developing, and producing crude petroleum plus the minimum return on the operator's capital necessary to sustain exploration. The economic costs of new oil supplies are calculated by the discounted cash flow rate of return method whereby revenues from the sale of oil and their attendant costs are projected yearly over the expected life of the reserve. Oil prices are adjusted within the economic model until the discounted cash flow rate of return to the producer (after federal income taxes) is 15 percent, the

minimum required, in our opinion, to maintain exploration levels. Detailed results of the economic calculations and the methods used in their derivation are contained within the text of the report.

One important factor affecting economic oil costs is the depletion allowance which has now been repealed for the nation's major producers. Calculations made previously using the same economic model but not included in this work have shown that elimination of the depletion allowance will increase economic costs of new oil by approximately 20 to 24 percent.

Submitted,

LaRUE, MOORE & SCHAFER

John D. LaRue, P.E.

SIGNED: May 1, 1975

DISCUSSION

Petroleum Exploration

The basic elements of petroleum exploration are much the same around the world. Crude oil production is the culmination of a man's idea -- the successful testing of a correct hypothesis of where oil might be found. Ideas come from many sources, such as a study of aerial photographs, reconnaissance seismic surveys, examination of logs from unsuccessful wells, and analogies with conditions elsewhere. Pursuit of exploration ideas may result in a piece of tangible information which strengthens the idea. This piece of information, which is frequently referred to as a "lead", may be nothing more than the subtle change in contour spacing on a map or the way a river changes its course as it flows through the plain.

Leads which offer the most promise are investigated by assigning additional geologists, geophysicists, engineers, and supporting staff to make interpretations of all available geologic data and postulate petroleum accumulations. If the idea still appears to have merit (in the order of one in one hundred will), the lead may be upgraded into a "prospect". At this point, leases are purchased, geophysical crews are engaged to make surveys, and geological core holes may be drilled. Exploration geologists and geophysicists will then interpret the new information to see if the original concept was valid. If the new data still supports the prospect (in many cases it will not)

and it appears to have sufficient commercial potential in relation to others being evaluated, the prospect is slated for one or more exploratory wells.

Proof of petroleum reserves comes only from drilling exploratory wells -- there is no other way. The best of modern geophysical techniques give only a shadowy inference of places to look for petroleum accumulations. The exploratory well may be productive or dry, but the odds greatly favor its being dry. In 1974, for example, 6,600 of the 8,600 exploratory wells drilled failed to find either oil or gas and were abandoned as dry holes. If the exploratory well is successful in finding oil, new oil reserves are added to the United States inventory. Reserves added by drilling are classified into three general categories: new fields, new reservoirs in old fields, and extensions to old fields. Reserves added by drilling have historically been revised upward, most commonly through implementation of enhanced oil recovery techniques.

Development and Exploitation

The foregoing, which is generally referred to as the exploratory phase in the life of an oil field, is followed by the development of the field when additional wells are drilled and equipment is installed to accommodate oil production.

Development investment is usually divided by accounting conventions into two categories: well drilling and equipping costs, and lease equipment costs. The well-associated costs include all

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conduits through which oil is produced to the surface and the wellhead assembly. Lease equipment includes surface and subsurface pumping equipment, pipelines to storage, and lease storage tanks required for holding and measuring crude petroleum before it is sold.

Exploitation of the field begins when the first well is placed on production and continues until operating costs equal the operating revenues at which time the field is abandoned. During the exploitation period which typically lasts 25 to 30 years, wells require continuing attention to keep oil production at economic levels; the costs of labor and materials to maintain equipment and oil production are referred to as producing or operating costs.

Economic Considerations

A glance at dry hole statistics on Table 4 shows that many failures accompany the successful wells which define new oil fields. Each failure represents a considerable expenditure of time and monies in terms of geophysical and geological cost, lease acquisition, general and administrative cost, and all other outlays attributable to getting the prospects to the point where they are abandoned or selected for drilling.

Any viable entity engaged in prospecting for and producing crude petroleum must generate enough economically successful ventures to pay for both its failures and successes. Moreover, to justify continuing exploration activity, the producer must

earn a return on investment commensurate with his risks. Should the producer do otherwise, petroleum exploratory activity would decline and firms having revenues from oil production would seek more secure investment opportunities. One tremendously complicating factor is that oil is discovered in a somewhat random fashion and a firm exploring for oil may continue in a net-loss position for several years before it can be determined that it is unable to continue or until a discovery is made which covers the previous losses.

In this study we have endeavored to set out in the most straightforward manner possible the relationship between oil found and cost attributable to the finding of that oil. The frame of reference is the entire United States during the past 16 years, exclusive of the Prudhoe Bay field in Alaska which is in a geological province for which we have very little history.

The 15 years prior to 1974 have been a period of declining petroleum exploratory activity. During this period, an increasing number of producers found that in the face of rising costs they could not find enough new oil to justify attempts to replace their reserves and, therefore, began de facto liquidation. Because of the random nature of petroleum finding, a few explorers prospered during this period, but most, and indeed the nationwide exploratory industry as we shall show later, did not.

We have quantified the effects of increasing costs and decreasing finding rates on the cost of new petroleum reserves in

the United States. It serves no useful purpose to state that finding costs are so much a barrel and lifting costs have increased to a specific level unless one is so familiar with the magnitude of these numbers that they can intuitively be converted into profitability. Since few people, even those within the petroleum industry, can readily make this transition, the historical economics of oil finding have been expressed in terms of the economic cost of new oil.

The economic cost of new oil is calculated by taking into account the amount of oil discovered in any one year and the cost of finding, developing, and producing that oil, plus the minimum rate of return on the operator's investment necessary to sustain activity. When the economic cost is compared to the actual selling price of crude oil, great insight is provided into the forces that drive petroleum exploration levels. The next section, "Methodology", gives a detailed account of how economic costs of new oil are calculated.

Methodology

Activity in petroleum exploration, like most endeavors, is driven by the producer's anticipation that he might improve his position. The major considerations in exploration decision-making are current petroleum prices, extrapolation of past economic experience, and the current laws and regulations concerning petroleum finding and extractive processes. If prior experience seems to justify continuation of exploration, the limiting

constraint then becomes the availability of risk capital which is normally generated internally since petroleum exploration ventures cannot be financed through commercial lending institutions.

In this study we have isolated historic yearly expenditures for petroleum exploration and development and the ultimate petroleum reserves added through drilling during the same year. These reserves were projected over their expected lives so that the future annual gross revenue from the sale of crude oil and its associated gas could be calculated. All costs associated with the oil production were deducted to calculate net cash flow to the producer after federal income taxes.

Laws concerning depletion allowance and investment tax credit in effect during the year of discovery were used in calculating the net cash flow since these factors were the ones influencing exploratory activity in that year. Maximum advantage of intangible drilling deductions and depletion was taken, which implicitly assumes that the producer had other income against which to deduct a large portion of intangible drilling costs.

Economic costs of new oil were calculated by the discounted cash flow rate of return method wherein oil prices were adjusted until the producer's discounted rate of return after federal income taxes was 15 percent, the minimum required, in our opinion, to maintain exploration levels. The discounted cash flow method was used in this study because it is a universally accepted

decision-making investment criterion in petroleum exploration and production ventures. Individual economic projections for the years 1959 through 1974 may be found on Tables 11 through 26. The bottom line of these projections is summarized on Table 1, which also includes as footnotes the derivation of the columns appearing on the economic projections. The exact calculation procedure and derivation of economic parameters may be followed by examining Tables 2 through 10.

No claim is made that the calculation is precise. One might correctly argue, for example, that the geological expenditures predate drilling by several years or that royalty expenses are substantially greater than the one-eighth used in the calculation or that oil wells cost more to operate than gas wells. These refinements were not made because basic data are not available to permit more detailed differentiation of the costs. Further, it is better, in our judgment, to handle the statistical data on a consistent basis rather than to introduce arbitrary assumptions which would add little to the accuracy of the calculations and would not materially change the results. A conscious effort has been made to perform the calculations in such a manner that the resulting economic costs of new oil are not overstated. In general, introduction of more detailed data and refinements in the technique would result in slightly higher oil prices; however, the methods used provide a consistent basis for making meaningful year-to-year comparisons.

Historical reserve additions in the United States are shown n Table 2. Total reserves added by drilling include extensions f old oil fields, discovery of new fields, and new reservoirs iscovered in old fields. A second category of reserve additions ncludes revisions to existing reserves which are the algebraic ummation of the positive and negative adjustments to reserves in ll of the fields in the United States. The oil reserve revi- ions show a long positive historic trend, primarily because ecovery factors have been increased as a result of secondary re- overy projects. Revisions listed in 1974, for example, may come bout in part because a West Texas field found in the 1960's was laced on waterflood in 1973.

Historically, each barrel of new reserve added through rilling will accrue an additional three-fourths barrel of oil hrough the revision process and the ultimate reserve added ust be credited to the year's exploratory efforts.

Table 3 is a compilation of historical expenditures in the nited States associated with exploring, developing, and pro- ucing crude petroleum for the years 1959 through 1973. Dril- ing statistics for the same period plus 1974 are on Table 4, nd Table 5 depicts the calculation of operating expenses allo- ated to oil wells, compiled from data presented on Tables 3 nd 4. Implicit in the calculation of operating expenses is the ssumption that operating costs for oil wells are the same as as wells. This assumption, which is required because oil and

gas well operating costs are not accounted for separately, tends to produce economic oil costs which are conservative, i.e., low, since operating costs for oil wells generally exceed those for gas wells.

Table 6 shows the combined capital cost for oil and gas wells as compiled from data on Table 3. Capital investments allocated to oil operations based on data appearing in previous tables are on Table 7. Also shown on Table 7 is the adjustment in capital expenditures in the Prudhoe Bay field so that the calculated capital costs apply to the United States, excluding Prudhoe Bay.

Cost components related to well drilling and completion costs are on Table 8, together with the cost index for the years 1968 through 1974. The basic cost data used for the years 1959 through 1973 have not yet been compiled for 1974; thus, it was necessary to use the supplemental material from Table 8 to estimate capital expenditures for 1974. Table 9 shows a comparison between drilling costs appearing on Table 4 and those computed from a completely different source listed on Table 8. The correlation between the two sources was judged satisfactory for use in estimating the drilling cost component of 1974 capital expenditures. Calculation procedures for estimating the total 1974 capital expenditures related to oil are shown on Table 10.

The detailed calculation of discounted cash flow rate of return and economic oil price for individual years from 1959

through 1974 is shown on Tables 11 through 26. The results of these calculations are summarized on Table 1 and footnotes appearing on Table 1 apply to Tables 11 through 26 as well.

Analysis of Results

The results of the calculations summarized on Table 1 are shown graphically on Figure 1, which depicts the economic cost of new oil and the price actually received for new oil during the same year. The East Texas field was chosen as a reference for new oil selling price because of its large size and long history of consistently tabulated oil prices.

Figure 2 shows the cost of the average well drilled during the period from 1959 through 1974, and Figure 3 shows the average monthly operating cost per well during the same interval, with 1974 being estimated by extrapolation of the curve. The trend in the amount of oil discovered per exploratory well is shown on Figure 4. Data presented on this figure are exclusive of allocated reserve revisions.

Figure 5 shows the number of drilling rigs sold at auction in the United States. The significance of these data is that auctions of drilling rigs are usually distress sales and most of the rigs sold in this manner are junked or dismantled and used for spare parts. The first drilling rig auction took place in 1960 and by the end of 1973 over 60 percent of the nation's drilling equipment had been permanently removed from drilling service. The reason for loss of the drilling rigs may be seen

in Figure 6, which depicts the total drilling activity in the United States. After four years of declining activity, an increasing number of drilling contractors were forced to sell their equipment and cease or reduce their operations.

Figure 7 is another activity indicator which shows total oil wells drilled. Figure 8 indicates the total exploratory well drilled in the United States, and Figure 9 shows the total footag drilled.

All of the activity indicators shown on Figures 6 through 9 have one thing in common: in the 15 years prior to 1974, the level of petroleum exploration had shown a continual decline. The reason for the reduction in activity is apparent from Figure 1, which shows that during the early 1960's the economic cost of new oil began to exceed the price for which it could be sold in the United States. By 1971, the economic cost of new oil was about $8.00 a barrel, or more than twice the selling price. A predictable consequence of the decline of petroleum activity was the sale of many substantial producers to larger or international firms and the beginning of the liquidation of the country's oil reserves.

By 1974, economic cost of new oil had increased to over $12.00, based on estimated 1974 capital expenditures and operating costs.

The first major reversal in the 15-year trend of declining exploration activity occurred as a result of increased worldwide

:roleum prices in late 1973, when the United States selling
ice of new oil reached $10.00 per barrel.

TABLES

LIST OF TABLES

TABLE 1

SUMMARY TABLE
COST OF NEW OIL
UNITED STATES
YEARS 1959 THROUGH 1974

YEAR	(1) GROSS OIL RESERVES MILLIONS OF BBLS	(2) GROSS GAS RESERVES BILLIONS OF CU FT	(3) GROSS OIL & GAS SALES MILLIONS OF $	(4) ROYALTY EXPENSE MILLIONS OF $	(5) AD VALOREM & STATE TAXES MILLIONS OF $	(6) OPERATING EXPENSES MILLIONS OF $	(7) ADJUSTED GROSS INCOME MILLIONS OF $	(8) TOTAL INVESTED CAPITAL MILLIONS OF $	(9) IN-TANGIBLE DRILLING COST MILLIONS OF $	(10) DEPLETION ALLOWANCE MILLIONS OF $	(11) DEPRE CIATION MILLIONS OF $	(12) TAXABLE INCOME MILLIONS OF $	(13) INVEST TAX CREDIT MILLIONS OF $	(14) FEDERAL INCOME TAXES MILLIONS OF $	(15) AFTER TAX NET INCOME MILLIONS OF $	(16) NET CASH FLOW MILLIONS OF $	(17) NET CASH FLOW DISC. 15% MILLIONS OF $	(18) GROSS OIL PRICE $ DOL	(19) GAS PRICE $/THOUS. CU FT
1959	3,759	4,661	11,659	1,457	675	1,870	7,656	3,630	2,341	2,345	857	2,113	0	1,056	6,600	2,970	0	2.86	0.194
1960	2,760	3,422	10,087	1,261	589	1,486	6,751	3,150	2,042	2,067	706	1,936	0	968	5,783	2,633	0	3.39	0.210
1961	2,748	3,408	9,939	1,242	562	1,512	6,623	3,120	2,048	2,034	701	1,840	0	920	5,703	2,583	0	3.34	0.227
1962	2,489	3,086	10,470	1,309	586	1,611	6,964	3,312	2,134	2,161	758	1,911	53	903	6,062	2,750	0	3.92	0.233
1963	2,114	2,621	9,639	1,205	533	1,546	6,355	3,095	2,074	1,987	718	1,576	50	738	5,617	2,522	0	4.27	0.237
1964	3,089	3,830	11,131	1,391	636	1,649	7,455	3,475	2,155	2,288	769	2,243	54	1,068	6,387	2,912	0	3.32	0.231
1965	2,214	2,745	9,525	1,191	547	1,512	6,276	3,007	2,096	1,950	733	1,497	51	697	5,579	2,492	0	4.01	0.234
1966	1,969	2,562	9,929	1,241	558	1,460	6,670	3,135	2,009	2,071	758	1,833	41	875	5,795	2,660	0	4.74	0.236
1967	1,857	1,909	9,730	1,216	564	1,408	6,541	3,132	2,088	2,026	753	1,674	43	794	5,747	2,615	0	4.99	0.240
1968	1,986	2,256	10,733	1,342	628	1,459	7,303	3,446	2,268	2,251	781	2,003	55	947	6,356	2,910	0	5.12	0.246
1969	1,509	1,903	11,063	1,383	635	1,475	7,570	3,406	2,112	2,341	757	2,360	37	1,143	6,427	3,021	0	7.01	0.251
1970	1,750	2,170	13,242	1,655	764	1,645	9,178	3,590	1,891	2,290	692	4,305	0	2,153	7,025	3,435	0	7.25	0.257
1971	1,255	1,488	10,735	1,342	600	1,527	7,266	3,032	1,751	1,846	606	3,063	42	1,489	5,777	2,745	0	8.23	0.273
1972	1,292	1,764	10,026	1,253	557	1,482	6,733	2,986	1,893	1,711	696	2,433	49	1,168	5,565	2,579	0	7.36	0.293
1973	1,040	1,451	9,454	1,182	507	1,436	6,329	2,846	1,855	1,614	669	2,191	47	1,049	5,280	2,434	0	8.70	0.279
1974	1,195	1,675	16,094	2,012	863	2,115	11,104	4,632	2,739	2,778	987	4,600	69	2,231	8,873	4,241	0	12.84	0.449

NOTE: Figures are for total United States except Prudhoe Bay field in Alaska. All financial data expressed in constant dollars for year of initial projection. Columns may not add precisely because of computer rounding.

Explanatory Notes:

Column

(1) Oil reserves added by drilling plus expected upward revisions. API; See Table 2, Column (8).
(2) Gas reserves associated with oil.
(3) Column (1) x Column (18) + Column (2) x Column (19).
(4) 12.5% of Column (3). Minimum royalty.
(5) Variable tax rate x (Column (3) - Column (4)). Tax rate is approximately 6%. JAS.
(6) Direct operating costs including field labor and supplies, maintenance, general and administrative overhead. JAS; See Table 5.
(7) Column (3) - Column (4) - Column (5) - Column (6).
(8) Total capital investment attributable to oil reserves added in year including leasehold costs. JAS; See Table 7, Line (11).
(9) Portion of total capital attributable to intangible drilling costs. JAS; See Table 7, Line (10).

Column

(10) Includes cost and percentage depletion based on law at time of first year projected.
(11) Cumulative depreciation of tangible drilling costs and leasehold equipment. JAS; See Table 7, Line (9).
(12) Column (7) - Column (9) - Column (10) - Column (11).
(13) Investment tax credit is variable for each year depending on law at start of year. Zero some years.
(14) Column (12) x 50% - Column (13).
(15) Column (7) - Column (14) or alternatively Column (12) - Column (14) + Column (10) + Column (9) + Column (11).
(16) Column (15) - Column (8).
(17) Column (16) discounted at 15% per annum compounded annually. Must total zero.
(18) Gross oil price at wellhead required for 15% discounted rate of return after federal income taxes.
(19) Gross gas price for the purpose of calculating co-product credits Bureau of Mines yearly average plus 50%.

TABLE 2

OIL RESERVE ADDITIONS THROUGH DRILLING
PLUS ALLOCATED HISTORICAL REVISIONS
UNITED STATES (a)
(Millions of Barrels)

Year	(1) Reserves at End of Year	(2) Revisions to Existing Reserves	(3) Reserves Added by Drilling During Year: Extensions	(4) New Fields	(5) New Reservoirs	(6) Totals	(7) Allocated Ultimate Revisions	(8) Ultimate Reserve Added
1946	20,874	1,255	1,159	(b)	244	1,403		
1947	21,488	749	1,270	(b)	445	1,715		
1948	23,280	1,959	1,440	269	127	1,836		
1949	24,649	604	1,694	544	346	2,584		
1950	25,268	663	1,334	408	157	1,899		
1951	27,468	1,776	2,249	206	183	2,638		
1952	27,961	744	1,509	280	216	2,006		
1953	28,945	1,265	1,440	344	248	2,031		
1954	29,561	538	1,749	308	278	2,335		
1955	30,012	696	1,698	220	257	2,175		
1956	30,435	805	1,702	235	232	2,170		
1957	30,300	465	1,543	207	209	1,959		
1958	30,536	955	1,339	151	164	1,654		
1959	31,719	1,519	1,779	166	204	2,148	1,611	3,759
1960	31,613	788	1,324	141	113	1,577	1,183	2,760
1961	31,759	1,087	1,209	107	254	1,570	1,178	2,748
1962	31,389	759	1,041	92	288	1,422	1,067	2,489
1963	30,970	966	858	97	253	1,208	906	2,114
1964	30,991	899	1,419	127	220	1,765	1,324	3,089
1965	31,352	1,783	793	237	235	1,265	949	2,214
1966	31,452	1,839	814	160	150	1,125	844	1,969
1967	31,377	1,901	716	125	220	1,061	796	1,857
1968	30,707	1,320	777	166	191	1,135	851	1,986
1969	29,632	1,258	615	96	151	862	647	1,509
1970	29,401(a)	2,089	631	253(a)	116	1,000	750	1,750
1971	28,463(a)	1,600	561	91	65	717	538	1,255
1972	26,739(a)	820	459	123	155	738	554	1,292
1973	25,700(a)	1,552	390	116	88	594	446	1,040
1974	24,650(a)	1,311	369	226	88	683	512	1,195
TOTALS		33,965	33,881	5,495	5,897	45,275		

Source: API. See Appendix A - I.

NOTE: Columns may not extend precisely because of computer rounding.
Definitions relating to reserve nomenclature may be found in Appendix A.

EXPLANATORY NOTES:

Column

(1) Proved oil reserves at end of year.
(2) Revisions to reserves included in Column (1).
(3) Extensions of old fields by drilling.
(4) New field discoveries.
(5) New reservoirs discovered in old fields.
(6) Column (3) + Column (4) + Column (5).
(7) (Total of Column (2) / Total of Column (6)) x yearly value of Column (6).
(8) Reserves added during year, Column (6) + Column (7).

FOOTNOTES:

(a) Excludes Prudhoe Bay field in Alaska.
(b) Included in Column (5).

TABLE 3

EXPENDITURES FOR EXPLORATION, DEVELOPMENT AND PRODUCTION
TOTAL UNITED STATES
YEARS 1959 THROUGH 1973
(Millions of Dollars)

Line	Investment Category Item	1959	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973
	1. Exploration															
(1)	a. Drilling and equipping exploratory wells	791	746	746	817	762	823	818	775	793	836	944	815	775	910	1,021
(2)	b. Acquiring undeveloped acreage	554	626	428	815	376	570	438	577	829	1,578	1,137	714	642	1,722	3,646
(3)	c. Lease rentals and expense for carrying leases	193	193	189	197	193	177	166	180	140	179	134	138	143	142	155
(4)	d. Geological and geophysical	320	277	280	299	300	336	355	378	392	373	387	349	361	372	429
(5)	e. Contributions toward test wells	30	28	28	30	28	31	31	28	34	34	33	30	24	35	38
(6)	f. Land department, leasing and scouting	0	104	115	108	117	100	102	70	86	82	93	98	100	105	102
(7)	g. Other, including direct overhead	124	71	65	58	69	72	61	128	122	136	168	143	142	147	181
(8)	h. G & A overhead allocated to exploration	183	197	219	213	200	215	207	195	206	204	210	189	206	239	293
(9)	i. TOTAL EXPLORATION	2,195	2,242	2,070	2,537	2,045	2,324	2,178	2,331	2,602	3,422	3,106	2,476	2,393	3,672	5,865
	2. Development															
(10)	a. Drilling and equipping development wells	1,830	1,651	1,624	1,729	1,512	1,574	1,553	1,557	1,472	1,539	1,634	1,733	1,573	1,869	2,016
(11)	b. Lease equipment	315	273	274	320	305	347	314	459	428	384	442	443	388	497	524
(12)	c. Improved recovery programs	103	92	95	114	112	132	124	187	247	222	303	285	323	310	276
(13)	d. Other, including direct overhead	65	58	60	72	71	84	78	119	169	188	180	170	185	160	189
(14)	e. G & A overhead allocated to development	154	148	159	167	164	161	170	168	192	199	207	220	202	257	250
(15)	f. TOTAL DEVELOPMENT	2,467	2,222	2,212	2,402	2,164	2,298	2,239	2,490	2,508	2,532	2,766	2,851	2,671	3,093	3,255
	3. Production															
(16)	a. Production expenditures, including direct overhead	1,450	1,390	1,455	1,535	1,581	1,613	1,685	1,895	1,933	2,094	2,189	2,379	2,504	2,563	2,792
(17)	b. Production or severance taxes	316	339	346	354	373	393	400	430	464	499	525	563	587	613	683
(18)	c. Ad valorem taxes	192	199	195	202	198	204	212	212	248	259	271	294	295	269	275
(19)	d. G & A overhead allocated to production	288	276	298	311	306	300	317	310	303	340	369	416	465	467	485
(20)	e. TOTAL PRODUCTION	2,246	2,204	2,294	2,402	2,458	2,510	2,614	2,847	2,948	3,192	3,354	3,652	3,851	3,912	4,235
(21)	4. Drilling and Production Platforms	0	8	16	30	39	57	64	113	147	174	0	0	0	0	0
(22)	5. TOTAL EXPENDITURES	6,908	6,676	6,592	7,371	6,706	7,189	7,095	7,781	8,205	9,320	9,226	8,979	8,915	10,677	13,355

NOTES:

A. All financial data expressed in current dollars for year shown.

B. Certain categories of expenditures prior to 1965 do not precisely conform to current formats and in some instances have been allocated.

C. Line (21), Platforms were included in Line (1) or Line (10) by JAS after 1968.

SOURCE:
Joint Association Survey of the U. S. Oil and Gas Producing Industry. See Appendix A for definitions of investment categories.

TABLE 4

DRILLING STATISTICS - TOTAL UNITED STATES
YEARS 1959 THROUGH 1974

Line		Units	1959	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
(1)	Total wells drilled	Wells	49,563	44,133	43,988	43,944	41,853	43,486	39,596	34,521	31,538	29,576	29,481	27,177	25,040	26,443	26,244	31,698
(2)	Oil	Wells	25,413	21,294	21,204	21,402	20,678	21,012	18,857	15,856	14,935	13,767	12,915	12,547	11,405	10,753	9,705	12,784
(3)	Gas	Wells	5,049	5,262	5,674	5,858	4,779	4,874	4,772	4,060	3,558	3,324	3,927	3,844	3,679	5,086	6,427	7,240
(4)	Dry holes	Wells	19,101	17,577	17,110	16,684	16,396	17,600	15,967	14,605	13,045	12,485	12,639	10,786	9,956	10,604	10,112	11,674
(5)	Oil wells + allocated dry holes	Wells	41,348	35,388	34,702	34,500	33,996	35,298	31,599	27,483	25,470	23,823	22,603	20,803	18,932	17,951	15,768	20,237
(6)	Total exploratory wells drilled	Wells	13,191	11,704	10,992	10,785	10,664	10,747	9,466	10,313	9,059	8,879	9,701	7,693	6,922	7,539	7,466	8,619
(7)	Oil	Wells	1,702	1,321	1,157	1,211	1,978	1,219	946	1,030	1,039	863	1,084	790	651	684	619	814
(8)	Gas	Wells	912	868	813	771	664	497	515	578	556	430	616	481	437	601	900	1,195
(9)	Dry holes	Wells	10,577	9,515	9,022	8,803	8,686	8,951	8,005	8,705	7,464	7,586	8,001	6,422	5,834	6,254	5,947	6,610
(10)	Oil wells + allocated dry holes	Wells	8,588	7,063	6,455	6,589	8,480	7,013	6,129	6,605	5,901	5,926	6,185	4,781	4,141	4,119	3,042	3,492
	Cost of wells drilled																	
(11)	Oil	Million $	1,321	1,111	1,087	1,161	1,071	1,063	1,067	986	995	1,089	1,117	1,088	895	1,005	1,007	
(12)	Gas	Million $	509	540	537	569	442	510	486	543	502	494	606	618	613	802	998	
(13)	Dry holes	Million $	821	774	774	847	790	854	848	832	802	826	888	873	864	1,006	1,070	
(14)	Total	Million $	2,651	2,424	2,398	2,577	2,303	2,427	2,401	2,361	2,299	2,409	2,611	2,579	2,371	2,814	3,075	4,923(a)
(15)	Average cost/well drilled	$	53,487	54,924	54,514	58,642	55,025	55,811	60,091	68,393	72,896	81,451	88,565	94,896	94,688	106,417	117,169	155,309(b)
(16)	Fraction of total cost attributed to oil		722	.673	.669	.671	.708	.676	.687	.645	.665	.688	.648	,638	.594	.556	.502	.526(c)
	Wells producing at year end																	
(17)	Oil	Wells	583,141	591,158	594,917	588,280	587,777	585,255	579,875	570,930	566,869	548,331	537,640	517,177	512,471	503,505	499,968	
(18)	Gas	Wells	83,225	90,761	96,809	102,545	111,511	112,899	115,834	124,092	121,758	123,528	125,020	118,864	117,300	119,167	123,034	
(19)	Total	Wells	666,366	681,919	691,726	690,825	699,288	698,154	695,709	695,022	688,627	671,859	662,660	636,041	629,771	622,672	623,002	

NOTE: All financial data expressed in current dollars for year shown. Columns may not extend precisely because of computer rounding.

EXPLANATORY NOTES:

Line

(1) Line (2) + Line (3) + Line (4).
(2) Source: JAS Survey, Section I.
(3) Source: JAS Survey, Section 1.
(4) Source. JAS Survey. Section 1.
(5) [Line (2) / (Line (2) + Line (3))] x Line (4) + Line (2).
(6) Line (7) + Line (8) + Line (9).
(7) Source: AAPG, API.
(8) Source: AAPG, API.
(9) Source: AAPG, API.
(10) [Line (7) / (Line (7) + Line (8))] x Line (9) + Line (7).
(11) Source: JAS Survey, Section 1.
(12) Source: JAS Survey, Section 1.
(13) Source: JAS Survey, Section 1

EXPLANATORY NOTES (cont'd).

Line

(14) Line (11) + Line (12) + Line (13)
(15) Line (14) / Line (1).
(16) Line (11) / (Line (11) + Line (1[illegible])
(17) Source: World Oil.
(18) Source: World Oil.
(19) Line (17) + Line (18)

FOOTNOTES:

(a) From Table 10, Line (3).
(b) From Table 9, Line (3) (Yr. 1974).
(c) Estimated from past trends and numbers of oil and gas wells drilled during 1974.

TABLE 5

OPERATING EXPENSES ALLOCATED TO OIL WELLS
TOTAL UNITED STATES
YEARS 1959 THROUGH 1974

Line	Cost Component (b)	Units	1959	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
(1)	Production expense including general overhead	Million $	1,450	1,390	1,455	1,535	1,581	1,685	1,685	1,895	1,933	2,094	2,189	2,379	2,504	2,563	[illegible]	
(2)	Exploitation geology	Million $	111	87	86	89	92	106	104	127	129	127	139	123	126	[illegible]	[illegible]	
(3)	Lease equipment replacement	Million $	79	68	69	80	76	79	79	115	107	96	92	104	116	[illegible]	[illegible]	
(4)	General and administrative overhead	Million $	288	276	298	311	306	317	317	310	303	340	369	416	465	467	485	
(5)	Total operating expenses	Million $	1,928	1,821	1,908	2,015	2,055	2,187	2,185	2,447	2,472	2,657	2,789	3,022	3,211	3,277	3,55[illegible]	
(6)	Number of producing wells and of year	Wells	666,366	681,919	691,726	690,825	699,288	695,709	695,709	695,022	688,627	671,859	662,660	636,041	629,771	622,672	623,002	
(7)	Per-well operating cost	$/year	2,893	2,670	2,758	2,917	2,939	3,144	3,141	3,521	3,590	3,955	4,209	4,751	5,098	5,263	5,700	
(8)	Per-well operating cost	$/month	241	223	230	243	245	262	262	293	299	330	353	397	422	440	476	509 (a)
(9)	New oil wells added during year	Wells	25,413	21,294	21,204	21,402	20,678	18,857	18,657	15,856	14,935	13,767	12,915	12,547	11,405	10,753	9,705	12,784
(10)	Annual operating expenses for new oil wells	Million $	73,512	56,868	58,464	62,448	60,780	59,208	58,584	55,812	53,604	54,444	54,708	59,748	57,804	56,712	55,464	78,085

NOTE. All financial data expressed current dollars for year shown. Columns may not extend precisely because of computer rounding.

EXPLANATORY NOTES:

Line

(1) From Table 3, Line (16).
(2) From Table 3, Lines ((4) + (7)) x .25 .
(3) From Table 3, Line (11) x .25 .
(4) From Table 3, Lina (19).
(5) Lines (1) + (2) + (3) + (4).
(6) From Table 4, Line (19).
(7) Line (5) / Line (6).
(8) Lina (7) / 12 months.
(9) From Table 4, Line (2).
(10) Line (9) x Line (7).

FOOTNOTES:

(a) Estimated, see Figure 3.
(b) Columna (1) through (8) include oil and gas wells. The same monthly operating cost was assumed for wells in both categories.

TABLE 6

CAPITAL INVESTMENTS FOR OIL AND GAS
TOTAL UNITED STATES
YEARS 1959 THROUGH 1973

Line		Units	1959	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973
	Well drilling and completion costs																
(1)	Exploratory wells	Million $	791	746	746	817	762	823	818	775	793	836	944	815	775	910	1,021
(2)	Development wells	Million $	1,830	1,651	1,624	1,729	1,512	1,574	1,553	1,557	1,472	1,539	1,634	1,733	1,573	1,869	2,016
(3)	Offshore drilling platforms	Million $	0	8	16	30	39	57	64	113	147	174	0	0	0	0	0
(4)	Total	Million $	2,621	2,405	2,386	2,576	2,313	2,454	2,435	2,445	2,412	2,549	2,578	2,548	2,348	2,779	3,037
(5)	Lease equipment associated with new production	Million $	236	205	206	240	229	260	236	344	321	288	332	332	291	373	393
(6)	Lease acquisitions	Million $	598(e)	598(e)	554	626	428	815	376	570	438	577	829	1,578	1,137	714	642
	Exploration drilling overhead																
(7)	Direct	Million $	93	53	49	44	52	54	46	96	92	102	126	107	107	110	136
(8)	General and administrative	Million $	183	197	219	213	200	215	207	195	206	204	210	189	206	239	293
	Development drilling overhead																
(9)	Direct	Million $	65	58	60	72	71	84	78	119	169	188	180	170	185	160	189
(10)	General and administrative	Million $	154	148	159	167	164	161	170	168	192	199	207	220	202	257	250
(11)	Geological and geophysical	Million $	240	208	210	224	225	252	266	284	294	280	290	262	271	279	322
(12)	Other exploration investment including land debt, lease rentals, and contributions toward test wells	Million $	223	325	332	335	338	308	299	278	260	295	260	266	267	282	295
(13)	Total capital costs for oil and gas	Million $	4,413	4,197	4,175	4,495	4,020	4,603	4,113	4,499	4,384	4,682	5,012	5,672	5,014	5,193	5,557

EXPLANATORY NOTES:

Line

(1) From Table 3, Line (1).
(2) From Table 3, Line (10).
(3) From Table 3, Line (21).
(4) Lines (1) + (2) + (3).
(5) From Table 3, Line (11) x 0.75.
(6) From Table 3, Line (2). NOTE: Lease acquisition costs were delayed two years after actual expenditure due to normal delay in development.
(7) From Table 3, Line (7) x .75.

NOTE: All financial data expressed in current dollars for year shown. Columns may not extend precisely because of computer rounding.

EXPLANATORY NOTES (cont'd)

Line

(8) From Table 3, Line (8).
(9) From Table 3, Line (13).
(10) From Table 3, Line (14).
(11) From Table 3, Line (4) x .75.
(12) From Table 3, Lines (3) + (5) + (6).
(13) Lines (4) + (5) + (6) + (7) + (8) + (9) + (10) + (11) + (12).

FOOTNOTES:

(e) Estimated.

TABLE 7

ALLOCATION OF CAPITAL INVESTMENT TO OIL OPERATIONS
TOTAL UNITED STATES
YEARS 1959 THROUGH 1974

Line		Units	1959	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
(1)	Total capital costs for oil and gas	Million $	4,413	4,197	4,175	4,495	4,020	4,603	4.113	4,499	4,384	4.682	5,012	5,672	5,014	5,193	5,557	
(2)	Fraction of capital costs attributable to oil operations	Fraction	.722	.673	.669	.671	.708	.676	.687	.645	.665	.688	.648	.638	.594	.556	.502	526(a)
(3)	Capital costs attributable to oil operations	Million $	3,186	2,825	2,793	3,016	2,846	3,112	2,826	2,902	2,915	3,221	3,248	3,619	2,978	2,887	2,790	4,578(b)
(4)	Adjustments to capital for Prudhoe Bay, North Slope, Alaska	Million $	0	0	0	0	0	0	0	0	0	10	21	235	92	55	67	87
(5)	Capital costs for oil less Prudhoe Bay investment	Million $	3,186	2,825	2,793	3,016	2,846	3,112	2,826	2,902	2,915	3,211	3,227	3,384	2,886	2,832	2,723	4,491
(6)	Supplement capital investment for improved recovery programs	Million $	444	326	325	294	250	365	262	233	219	235	178	207	148	153	123	141
(7)	Total adjusted capital costs for oil operations	Million $	3,630	3,151	3,118	3,310	3,096	3,477	3,088	3,135	3,134	3,446	3,405	3,591	3,034	2,985	2,846	4,632
	Recap for federal income tax calculations																	
(8)	Leasehold costs	Million $	432	402	371	420	303	551	258	368	291	397	537	1,007	675	397	322	906(c)
(9)	Tangible investment	Million $	857	708	700	757	718	769	732	759	753	782	758	692	605	698	669	987(d)
(10)	Intangible investment	Million $	2,341	2,041	2,047	2,133	2,075	2,157	2,098	2,008	2,090	2,267	2,110	1,892	1,754	1,890	1,855	2,739(e)
(11)	Total	Million $	3,630	3,151	3,118	3,310	3,096	3,477	3,088	3,135	3,134	3,446	3,405	3,591	3,034	2,985	2,846	4.632
(12)	Ratio of tangible to tangible plus intangible investment	Fraction	.268	.257	.255	.262	.257	.263	.259	.274	.265	.256	.264	.268	.257	.269	.265	.265(f)

NOTE: All financial data expressed in current dollars for year shown. Columns may not extend precisely because of computer rounding.

EXPLANATORY NOTES:

Line

(1) From Table 6, Line (13).
(2) From Table 4, Line (16).
(3) Line (1) x Line (2).
(4) Estimated based on drilling activity in Alaska.
(5) Line (3) - Line (4).
(6) Based on $0.276 per barrel of secondary reserves added.
(7) Line (5) + Line (6).
(8) Line (6), Table 6, x Line (2), above.
(9) {[(Line (4), Table 6, x .30) + Line (5), Table 6] x Line (2), above / (Line (3), above - Line (8), above)} x (Line (7), above - Line (8) above)

EXPLANATORY NOTES (cont'd)

Line

(10) Line (7) - Line (9) - Line (8).
(11) Lines (8) + (9) + (10).
(12) Line (9) / (Lines (9) + (10))

FOOTNOTES:

(a) From Table 10, Line (4).
(b) From Table 10, Line (13).
(c) From Table 10, Line (12).
(d) (Line (7) - Line (8)) x Line (12).
(e) Line (7) - Line (8) - Line (9).
(f) Average of years 1969 through 1973.

TABLE 9

PROJECTION OF DRILLING COSTS FOR YEAR 1974
TOTAL UNITED STATES

Line		Units	1968	1969	1970	1971	1972	1973	1974	Average Deviation
(1)	Average actual drilling cost per well	Thousand $	81.4	88.6	94.9	94.7	106.4	117.2	--	
(2)	IPAA index of drilling and equipping wells (1969 base)	Percent	95.0	100.0	105.4	113.7	122.9	130.2	175.3	
(3)	Calculated average cost per well based on IPAA index (1969 base)	Thousand $	84.2	88.6	93.4	100.7	108.9	115.4	155.3	
(4)	Deviation of calculated drilling cost per well from actual cost per well	Percent	+3.2	0	-1.6	+6.3	+2.3	-1.5	--	+1.45

NOTE: All financial data expressed in current dollars for year shown. Columns may not extend precisely because of computer rounding.

EXPLANATORY NOTES:

Line

(1) From Joint Association Survey, Section I. Includes oil and gas wells and dry holes. (See Table 4, Line (15).)
(2) See Table 8.
(3) IPAA index x base year actual cost (1969) = Calculated drilling cost. For 1974: 175.3 x 88,600 = $155,300.
(4) [(Line (3) / Line (1)) - 1.0] 100.

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TABLE 10

CALCULATION PROCEDURE
TOTAL UNITED STATES
1974 INVESTMENT COST DATA

Line		Units	Extension
(1)	1974 drilling cost per well	$	155,300
(2)	Total wells drilled in 1974	Wells	31,698
(3)	Total 1974 drilling costs	Million $	4,923
(4)	Fraction of total drilling cost applicable to oil wells, 1974	Fraction	.526
(5)	1974 drilling cost applicable to oil	Million $	2,589
(6)	1973 capital costs related to oil less lease acquisition costs	Million $	2,467
(7)	1973 drilling costs applicable to oil	Million $	1,525
(8)	1973 other capital costs	Million $	942
(9)	Estimated increase to 1974 for other capital costs	Percent	15
(10)	1974 other capital costs	Million $	1,083
(11)	1974 total capital costs related to oil less lease acquisitions	Million $	3,672
(12)	1974 lease acquisitions	Million $	906
(13)	1974 total capital costs related to oil	Million $	4,578

EXPLANATORY NOTES:

Line

(1) See Table 9.
(2) From Table 4, Line (1).
(3) Line (1) x Line (2).
(4) Estimated from past trends and numbers of oil and gas wells drilled during 1974.
(5) Line (3) x Line (4).
(6) (Line (13), Table 6 - Line (6), Table 6) x Line (2), Table 7.
(5,557 - 642) x 0.502 = 2,467.
(7) Line (4), Table 6 x Line (2), Table 7.
3,037 x 0.502 = 1,525.
(8) Line (6) - Line (7).
(9) Estimated from Bureau of Labor Statistics:

	1973	1974	Percent Increase
Wholesale Price Index			
All commodities	134.7	160.1	18.8
Machinery & equipment	121.7	139.4	14.5
Employment & Earnings			
Crude petroleum & natural gas fields (a)	191.82	223.86	16.7
Oil & gas extraction (a)	181.47	214.97	18.5

(10) Line (8) + (Line (9) / 100) x Line (8).
(11) Line (5) + Line (10).
(12) From Table 3, Line (2) (Yr. 1972) x Line (4), above.
(13) Line (11) + Line (12).

FOOTNOTES:

(a) Weekly earnings.

TABLE 11

COST OF NEW OIL
RESERVES ADDEO IN 1959
TOTAL UNITED STATES

TIME YEARS	(1) GROSS OIL PRODUCTION THOUSANDS OF BBLS	(2) GROSS GAS PRODUCTION MILLIONS OF CU-FT	(3) GROSS OIL & GAS SALES THOUSANDS OF $	(4) ROYALTY EXPENSE THOUSANDS OF $	(5) ADVALOREM & STATE TAXES THOUSANDS OF $	(6) OPERATING EXPENSES THOUSANDS OF $	(7) ADJUSTED GROSS INCOME THOUSANDS OF $	(8) TOTAL INVESTED CAPITAL THOUSANDS OF $
1959	126886	159819	399758	49970	23156	36756	289876	3186000
1960	257772	319637	799515	99939	46312	73512	579752	0
1961	257772	319637	799516	99940	46312	73512	579752	0
1962	257772	319637	799515	99939	46312	73512	579752	0
1963	257772	319638	799516	99939	46312	73512	579753	0
1964	257772	319637	799515	99940	46312	73512	579752	444000
1965	257772	319637	799516	99939	46312	73512	579752	0
1966	254091	315073	788097	98512	45650	73512	570422	0
1967	229558	284652	712008	89001	41243	73512	508252	0
1968	204318	253354	633720	79215	36708	73512	444285	0
1969	181852	225497	564040	70505	32672	73512	387351	0
1970	161857	200703	502021	62753	29080	73512	336677	0
1971	144060	178634	446822	55853	25882	73512	291575	0
1972	128220	158993	397692	49711	23036	73512	251433	0
1973	114122	141511	353965	44246	20504	73512	215703	0
1974	101574	125951	315044	39381	18249	73512	183903	0
1975	90405	112103	280405	35050	16242	73512	155599	0
1976	80465	99776	249572	31197	14457	73512	130408	0
1977	71617	88806	222132	27766	12867	73512	107986	0
1978	63743	79041	197707	24713	11452	73512	88029	0
SUB-TOTAL	3501400	4341736	10860075	1357510	629070	1433484	7440012	3630000
REMAINING 5.94 YRS	257600	319424	798983	99873	46281	436494	216336	0
TOTAL	3759000	4661160	11659058	1457383	675351	1869978	7656348	3630000

TIME YEARS	(9) INTANGIBLE DRILLING COSTS THOUSANDS OF $	(10) DEPLETION ALLOWANCE THOUSANDS OF $	(11) DEPRE-CIATION THOUSANDS OF $	(12) TAXABLE INCOME THOUSANDS OF $	(13) INVEST-MENT TAX CREDITS THOUSANDS OF $	(14) FEDERAL INCOME TAXES THOUSANDS OF $	(15) AFTER TAX NET INCOME THOUSANDS OF $	(16) NET CASH FLOW THOUSANDS OF $	(17) NET CASH FLOW DISC. 15% THOUSANDS OF $
1959	2015928	14812	25307	-1766170	0	-883084	1172961	-2013038	-1877167
1960	0	179648	50613	349491	0	174744	405007	405006	328408
1961	0	179647	50613	349491	0	174746	405006	405006	285573
1962	0	179648	50613	349492	0	174746	405007	405007	248324
1963	0	179648	50613	349491	0	174746	405006	405006	215935
1964	325008	96164	62414	96165	0	48082	531670	87670	40645
1965	0	179648	62415	337690	0	168845	410907	410907	165656
1966	0	177082	61523	331817	0	165909	404514	404514	141808
1967	0	159965	55583	292684	0	146341	361910	361910	110324
1966	0	142394	49472	252419	0	126210	318075	318075	84314
1969	0	126737	44032	216581	0	108291	279060	279060	64324
1970	0	112802	39191	184685	0	92342	244335	244335	48973
1971	0	100399	34881	156294	0	78147	213428	213428	37199
1972	0	89360	31046	131027	0	65514	185919	165919	28177
1973	0	79534	27633	108537	0	54268	161435	161435	21276
1974	0	70790	24594	88520	0	44260	139643	139643	16003
1975	0	63005	21890	70703	0	35352	120248	120248	11983
1976	0	55462	19483	55463	0	27731	102676	102676	8897
1977	0	45323	17341	45322	0	22661	85325	85325	6429
1976	0	36298	15434	36298	0	18149	69880	69880	4579
SUB-TOTAL	2340936	2268385	794691	2036000	0	1018000	6422012	2792013	-8340
REMAINING 5.94 YRS	0	76981	62373	76981	0	38490	177845	177845	8340
TOTAL	2340936	2345366	857064	2112981	0	1056490	6599857	2969858	0

GROSS OIL PRICE $ 2.86 / BBL
GROSS GAS PRICE $ .194 / THOUSAND CU-FT
TOTAL RESERVE LIFE 25.94 YEARS
LEASEHOLD INVESTMENT (000) $ 432000.

ROYALTY INTEREST 12.50 %
FEDERAL INCOME TAX RATE 50.00 %
ADVALOREM AND STATE TAX RATE 6.62 %

TABLE 12

COST OF NEW OIL
RESERVES ADDED IN 1960
TOTAL UNITED STATES

TIME YEARS	(1) GROSS OIL PRODUCTION THOUSANDS OF BBLS	(2) GROSS GAS PRODUCTION MILLIONS OF CU-FT	(3) GROSS OIL & GAS SALES THOUSANDS OF $	(4) ROYALTY EXPENSE THOUSANDS OF $	(5) ADVALOREM & STATE TAXES THOUSANDS OF $	(6) OPERATING EXPENSES THOUSANDS OF $	(7) ADJUSTED GROSS INCOME THOUSANDS OF $	(8) TOTAL INVESTED CAPITAL THOUSANDS OF $
1960	94644	117359	345889	43236	20187	28434	254032	2824000
1961	189288	234717	691777	86472	40374	56868	508063	0
1962	189288	234717	691776	86473	40374	56868	508064	0
1963	189288	234717	691778	36472	40374	56868	508063	0
1964	189288	234717	691777	86472	40373	56868	508064	0
1965	189288	234717	691778	86472	40374	56868	508064	326000
1966	189288	234717	691776	86472	40374	56868	508063	0
1967	186547	231318	681760	85220	39789	56868	499883	0
1968	168294	208685	615051	76882	35696	56868	445406	0
1969	149541	185431	546518	68314	31896	56868	389439	0
1970	132878	164769	485620	60703	28342	56868	339708	0
1971	116072	146409	431509	53939	25184	56868	295518	0
1972	104915	130094	383426	47928	22378	56868	256252	0
1973	93225	115599	340702	42588	19884	56868	221362	0
1974	82837	102718	302738	37842	17669	56868	190359	0
1975	73606	91272	269005	33625	15700	56868	162812	0
1976	65405	81102	239029	29879	13950	56868	138332	0
1977	58116	72064	212396	26550	12396	56868	116582	0
1978	51641	64035	188728	23591	11015	56868	97255	0
1979	45867	56900	167699	20962	9787	56868	80081	0
SUB-TOTAL	2561336	3176057	9360735	1170092	546316	1108926	6535402	3150000
REMAINING 6.63 YRS	196664	246343	726044	90755	42374	376855	216059	0
TOTAL	2760000	3422400	10086779	1260847	586690	1485781	6751461	3150000

TIME YEARS	(9) INTANGIBLE DRILLING COSTS THOUSANDS OF $	(10) DEPLETION ALLOWANCE THOUSANDS OF $	(11) DEPRE-CIATION THOUSANDS OF $	(12) TAXABLE INCOME THOUSANDS OF $	(13) INVEST-MENT TAX CREDITS THOUSANDS OF $	(14) FEDERAL INCOME TAXES THOUSANDS OF $	(15) AFTER TAX NET INCOME THOUSANDS OF $	(16) NET CASH FLOW THOUSANDS OF $	(17) NET CASH FLOW DISC. 15% THOUSANDS OF $
1960	1799546	13785	21345	-1580643	0	-790321	1044354	-1779645	-1659528
1961	0	155356	42689	310017	0	155008	353054	353053	286282
1962	0	155356	42690	310018	0	155009	353055	353055	248942
1963	0	155357	42669	310018	0	155009	353055	353055	216471
1964	0	155356	42690	310017	0	155009	353054	353054	188235
1965	242218	107422	51000	107423	0	53711	454353	128353	59507
1966	0	155357	51001	301707	0	150853	357210	357210	144008
1967	0	153106	50292	296514	0	148258	351625	351625	123267
1968	0	138125	45344	261937	0	130968	314438	314438	95852
1969	0	122735	40291	226413	0	113207	276232	276232	73223
1970	0	109058	35802	194846	0	97424	242284	242284	55847
1971	0	96906	31812	166799	0	83399	212119	212119	42516
1972	0	86106	26268	141877	0	70939	185314	185314	32298
1973	0	76514	25117	119731	0	59865	161496	161496	24477
1974	0	67987	22319	100053	0	50026	140333	140333	18494
1975	0	60412	19832	82567	0	41284	121527	121527	13927
1976	0	53660	17623	67031	0	33515	104818	104818	10445
1977	0	47699	15658	53224	0	26613	89970	89970	7797
1978	0	41670	13914	41671	0	20835	76419	76419	5758
1979	0	33859	12363	33859	0	16929	63152	63152	4138
SUB-TOTAL	2041764	1985848	652709	1855080	0	927541	5607862	2457862	-8044
REMAINING 6.63 YRS	0	81267	53527	81266	0	40633	175426	175426	8044
TOTAL	2041764	2067115	706236	1936346	0	968174	5783288	2633288	0

GROSS OIL PRICE $ 3.39 / BBL
GROSS GAS PRICE $ .210 / THOUSAND CU-FT
TOTAL RESERVE LIFE 26.63 YEARS
LEASEHOLD INVESTMENT (000) $ 402000.

ROYALTY INTEREST 12.50 %
FEDERAL INCOME TAX RATE 50.00 %
ADVALOREM AND STATE TAX RATE 6.67 %

TABLE 13

COST OF NEW OIL
RESERVES ADDED IN 1961
TOTAL UNITED STATES

TIME YEARS	(1) GROSS OIL PRODUCTION THOUSANDS OF BBLS	(2) GROSS GAS PRODUCTION MILLIONS OF CU-FT	(3) GROSS OIL & GAS SALES THOUSANDS OF $	(4) ROYALTY EXPENSE THOUSANDS OF $	(5) ADVALOREM & STATE TAXES THOUSANDS OF $	(6) OPERATING EXPENSES THOUSANDS OF $	(7) ADJUSTED GROSS INCOME THOUSANDS OF $	(8) TOTAL INVESTED CAPITAL THOUSANDS OF $
1961	94230	116845	340821	42603	19265	29232	249722	2795000
1962	186460	233691	681643	85205	38530	56464	499443	0
1963	186460	233690	681642	85205	36530	58464	499443	0
1964	186460	233690	681643	85206	36529	58464	499444	0
1965	186460	233691	681642	85205	36530	58464	499443	0
1966	186460	233690	681643	85205	36530	58464	499443	325000
1967	186460	233691	681642	85206	36530	58464	499444	0
1968	185745	230323	671821	83977	37975	58464	491405	0
1969	167657	207695	606403	75800	34277	58464	437861	0
1970	149066	184842	539157	67395	30475	58464	382823	0
1971	132536	164344	479369	59921	27097	56464	333887	0
1972	117638	146120	426211	53277	24091	56464	290379	0
1973	104771	129916	378947	47366	21420	58464	251695	0
1974	93153	115509	336925	42116	19045	56464	217301	0
1975	82623	102701	299563	37445	16933	58464	186720	0
1976	73038	91311	266343	33293	15055	56464	159531	0
1977	65473	61186	230608	29601	13385	58464	135358	0
1978	50212	72183	210548	26318	11902	58464	113864	0
1979	51757	64179	187200	23400	10581	58464	94755	0
1980	46017	57061	166441	20805	9408	56464	77763	0
SUB-TOTAL	2553676	3166556	9236411	1154551	522088	1140048	6419724	3120000
REMAINING 6.36 YRS	194324	240962	702852	87857	39729	372059	203208	0
TOTAL	2748000	3407520	9939263	1242408	561817	1512107	6622932	3120000

TIME YEARS	(9) INTANGIBLE DRILLING COSTS THOUSANDS OF $	(10) DEPLETION ALLOWANCE THOUSANDS OF $	(11) DEPRE-CIATION THOUSANDS OF $	(12) TAXABLE INCOME THOUSANDS OF $	(13) INVEST-MENT TAX CREDITS THOUSANDS OF $	(14) FEDERAL INCOME TAXES THOUSANDS OF $	(15) AFTER TAX NET INCOME THOUSANDS OF $	(16) NET CASH FLOW THOUSANDS OF $	(17) NET CASH FLOW DISC. 15% THOUSANDS OF $
1961	1803880	12722	21196	-1590075	0	-795037	1044759	-1750240	-1632107
1962	0	153424	42391	303627	0	151813	347630	347629	281883
1963	0	153425	42391	303626	0	151814	347630	347630	245116
1964	0	153424	42391	303627	0	151814	347629	347629	213145
1965	0	153425	42391	303626	0	151814	347630	347630	185343
1966	242125	163353	50612	103353	0	51676	447766	122766	56917
1967	0	153425	50612	295407	0	147704	351740	351740	141803
1968	0	151214	49632	290309	0	145154	346251	346251	121383
1969	0	136489	45026	256346	0	126173	309688	309686	94404
1970	0	121354	40032	221437	0	110719	272104	272104	72129
1971	0	107697	35593	190396	0	95198	238689	238689	55017
1972	0	95931	31646	162801	0	61401	208978	208978	41887
1973	0	85294	28137	138264	0	69132	182563	182563	31819
1974	0	75635	25016	116449	0	58225	159076	159076	24110
1975	0	67426	22243	97052	0	48526	138194	138194	18212
1976	0	59949	19776	79607	0	39903	119628	119628	13710
1977	0	53301	17503	64474	0	32237	103121	103121	10276
1978	0	47390	15633	50841	0	25420	88444	88444	7664
1979	0	40427	13699	40427	0	20214	74541	74541	5616
1980	0	32703	12358	32703	0	16351	61412	61412	4024
SUB-TOTAL	2046005	1958406	646806	1764503	0	882251	5537473	2417473	-7649
REMAINING 6.36 YRS	0	75511	52187	75510	0	37756	165452	165452	7649
TOTAL	2046005	2033919	700995	1840013	0	920007	5702925	2582925	0

GROSS OIL PRICE	$ 3.34 / BBL		ROYALTY INTEREST	12.50 %
GROSS GAS PRICE	$ .227 / THOUSAND CU-FT		FEDERAL INCOME TAX RATE	50.00 %
TOTAL RESERVE LIFE	26.36 YEARS		ADVALOREM AND STATE TAX RATE	6.46 %
LEASEHOLD INVESTMENT (000)	$ 371000.			

TABLE 14

COST OF NEW OIL
RESERVES AOOED IN 1962
TOTAL UNITED STATES

TIME YEARS	(1) GROSS OIL PROOUCTION THOUSANDS OF BBLS	(2) GROSS GAS PRODUCTION MILLIONS OF CU-FT	(3) GROSS OIL & GAS SALES THOUSANDS OF $	(4) ROYALTY EXPENSE THOUSANOS OF $	(5) AOVALOREM & STATE TAXES THOUSANDS OF $	(6) OPERATING EXPENSES THOUSANOS OF $	(7) ADJUSTEO GROSS INCOME THOUSANDS OF $	(8) TOTAL INVESTED CAPITAL THOUSANDS OF $
1962	85308	105782	358847	44856	20095	31224	262672	3018000
1963	170616	211564	717693	89712	40191	62448	525343	0
1964	170616	211564	717694	89711	40191	62448	525343	0
1965	170616	211563	717693	89712	40191	62448	525343	0
1966	170616	211564	717694	89712	40191	62448	525343	0
1967	170616	211564	717693	89711	40191	62448	525343	294000
1966	170616	211564	717694	89712	40190	62448	525343	0
1969	168164	208524	707380	88422	39614	62448	516896	0
1970	151831	188270	638674	79835	35765	62448	460626	0
1971	135037	167445	566029	71003	31810	62448	402768	0
1972	120100	148924	505200	63150	28291	62448	351310	0
1973	106815	132452	449316	56165	25162	62448	305544	0
1974	95001	117801	399619	49952	22379	62448	264840	0
1975	84493	104770	355416	44428	19903	62448	228638	0
1976	75146	93182	316104	39512	17702	62448	196440	0
1977	66635	82875	281138	35143	15744	62448	167805	0
1978	59442	73708	250042	31255	14002	62448	142336	0
1979	52867	65555	222384	27798	12453	62448	119685	0
1980	47019	58304	197767	24723	11077	62448	99539	0
1961	41819	51855	175908	21989	9850	62448	81621	0
SUB-TOTAL	2313573	2866830	9732007	1216500	544992	1217736	6752777	3312000
REMAINING 6.29 YRS	175427	217530	737933	92242	41325	392924	211443	0
TOTAL	2469000	3086360	10469940	1308742	586317	1610660	6964220	3312000

TIME YEARS	(9) INTANGIBLE DRILLING COSTS THOUSANDS OF $	(10) DEPLETION ALLOWANCE THOUSANDS OF $	(11) DEPRE-CIATION THOUSANOS OF $	(12) TAXABLE INCOME THOUSANDS OF $	(13) INVEST-MENT TAX CREDITS THOUSANDS OF $	(14) FEDERAL INCOME TAXES THOUSANDS OF $	(15) AFTER TAX NET INCOME THOUSANDS OF $	(16) NET CASH FLOW THOUSANDS OF $	(17) NET CASH FLOW DISC. 15% THOUSANDS OF $
1962	1917324	14395	23329	-1692376	25	-846213	1108885	-1909114	-1780258
1963	0	161643	46659	317040	47622	110898	414445	414444	336061
1964	0	161642	46659	317042	0	158521	366822	366822	258650
1965	0	161643	46659	317041	0	156520	366822	366822	224912
1966	0	161642	46659	317042	0	158521	366822	366822	195576
1967	216972	127039	54295	127038	5392	56127	467216	173216	80306
1968	0	161642	54294	309406	0	154703	370640	370640	149423
1969	0	159320	53514	304063	0	152032	364865	364865	127908
1970	0	143845	48317	268464	0	134232	326394	326394	99497
1971	0	127935	42972	231862	0	115931	286837	286837	76034
1972	0	113763	38219	199307	0	99653	251657	251657	58007
1973	0	101196	33991	170355	0	85178	220366	220366	44169
1974	0	90004	30232	144604	0	72302	192538	192538	33558
1975	0	80049	26887	121702	0	60851	167787	167787	25429
1976	0	71194	23914	101332	0	50666	145774	145774	19212
1977	0	63319	21269	83217	0	41608	126197	126197	14462
1976	0	56316	16915	67105	0	33553	108784	108784	10840
1979	0	50087	16824	52774	0	26387	93297	93297	8085
1980	0	42268	14963	42288	0	21144	78395	78395	5907
1961	0	34156	13308	34157	0	17078	64543	64543	4229
SUB-TOTAL	2134296	2083140	701879	1833463	53040	863692	5689085	2577086	-7993
REMAINING 6.29 YRS	0	77809	55825	77809	0	38905	172538	172538	7993
TOTAL	2134296	2160949	757704	1911272	53040	902597	6061623	2749624	0

GROSS OIL PRICE	$ 3.92 / BBL	ROYALTY INTEREST	12.50 %
GROSS GAS PRICE	$ .233 / THOUSAND CU-FT	FEDERAL INCOME TAX RATE	50.00 %
TOTAL RESERVE LIFE	26.29 YEARS	ADVALOREM AND STATE TAX RATE	6.40 %
LEASEHOLD INVESTMENT (000)	$ 420000.		

TABLE 15

COST OF NEW OIL
RESERVES ADDED IN 1963
TOTAL UNITED STATES

TIME YEARS	(1) GROSS OIL PRODUCTION THOUSANDS OF BBLS	(2) GROSS GAS PRODUCTION MILLIONS OF CU-FT	(3) GROSS OIL & GAS SALES THOUSANDS OF $	(4) ROYALTY EXPENSE THOUSANDS OF $	(5) ADVALOREM & STATE TAXES THOUSANDS OF $	(6) OPERATING EXPENSES THOUSANDS OF $	(7) ADJUSTED GROSS INCOME THOUSANDS OF $	(8) TOTAL INVESTED CAPITAL THOUSANDS OF $
1963	72486	89883	330496	41312	16276	30390	240517	2845000
1964	144972	179765	660992	82624	36553	60780	481035	0
1965	144972	179765	660991	82624	36553	60780	481035	0
1966	144972	179765	660992	82624	36553	60780	481035	0
1967	144972	179766	660992	82624	36553	60780	481035	0
1968	144972	179765	660992	82624	36553	60780	481035	250000
1969	144972	179765	660992	82624	36552	60780	481035	0
1970	142901	177198	651551	81444	36031	60780	473297	0
1971	129104	160089	588641	73580	32552	60780	421729	0
1972	114908	142485	523915	65489	28973	60780	368673	0
1973	102272	126816	466305	58288	25786	60780	321450	0
1974	91027	112873	415030	51879	22951	60780	279420	0
1975	81017	100461	369393	46174	20428	60780	242012	0
1976	72108	89414	326774	41097	16181	60760	208716	0
1977	64180	79583	292623	36578	16182	60780	179083	0
1978	57122	70831	260446	32556	14403	60780	152707	0
1979	50841	63043	231807	28975	12819	60780	129233	0
1980	45250	56111	206317	25790	11409	60780	108338	0
1981	40275	49941	183631	22954	10155	60780	89742	0
1982	35846	44449	163439	20430	9036	60780	73191	0
SUB-TOTAL	1969170	2441770	8978318	1122290	496501	1185210	6174318	3095000
REMAINING 5.94 YRS	144831	179590	660347	82543	36517	360788	180498	0
TOTAL	2114001	2621360	9638665	1204833	533018	1545998	6354816	3095000

TIME YEARS	(9) INTANGIBLE DRILLING COSTS THOUSANDS OF $	(10) DEPLETION ALLOWANCE THOUSANDS OF $	(11) DEPRE-CIATION THOUSANDS OF $	(12) TAXABLE INCOME THOUSANDS OF $	(13) INVEST-MENT TAX CREDITS THOUSANDS OF $	(14) FEDERAL INCOME TAXES THOUSANDS OF $	(15) AFTER TAX NET INCOME THOUSANDS OF $	(16) NET CASH FLOW THOUSANDS OF $	(17) NET CASH FLOW DISC. 15% THOUSANDS OF $
1963	1680700	10369	22401	-1680977	25	-840513	1081032	-1763967	-1644908
1964	0	149000	44801	287233	45706	97911	363123	383122	310664
1965	0	146999	44801	287235	0	143617	337417	337417	237915
1966	0	148999	44801	287235	0	143617	337418	337418	206087
1967	0	148999	44801	287235	0	143618	337417	337417	179899
1968	185750	122056	51173	122056	4497	56530	424505	174505	60904
1969	0	148999	51174	280862	0	140431	340604	340604	137313
1970	0	146871	50443	275982	0	137992	335305	335305	117546
1971	0	132690	45572	243468	0	121733	299996	299996	91450
1972	0	116099	40561	210012	0	105006	263667	263667	69892
1973	0	105114	36101	180235	0	90118	231332	231332	53322
1974	0	93555	32132	153734	0	76867	202553	202553	40590
1975	0	85267	20596	130146	0	65073	176939	176939	30639
1976	0	74112	25454	109151	0	54575	154141	154141	23361
1977	0	65962	22654	90466	0	45233	133850	133850	17640
1978	0	58709	20164	73834	0	36918	115790	115790	13270
1979	0	52253	17946	59033	0	29516	99716	99716	9937
1980	0	46183	15973	46183	0	23091	85247	85247	7387
1981	0	37763	14217	37762	0	18882	70861	70861	5339
1982	0	30269	12653	30269	0	15134	58056	58056	3804
SUB-TOTAL	2074456	1922288	666420	1511155	50228	705349	5468968	2373969	-6944
REMAINING 5.94 YRS	0	64667	51124	64687	0	32344	148155	148155	6944
TOTAL	2074456	1966975	717544	1575842	50228	737693	5617123	2522124	0

GROSS OIL PRICE $ 4.27 / BBL
GROSS GAS PRICE $ .237 / THOUSAND CU-FT
TOTAL RESERVE LIFE 25.94 YEARS
LEASEHOLD INVESTMENT (000) $ 303000.

ROYALTY INTEREST 12.50 %
FEDERAL INCOME TAX RATE 50.00 %
ADVALOREM AND STATE TAX RATE 6.32 %

TABLE 16

COST OF NEW OIL
RESERVES ADDED IN 1964
TOTAL UNITED STATES

TIME YEARS	(1) GROSS OIL PRODUCTION THOUSANDS OF BBLS	(2) GROSS GAS PRODUCTION MILLIONS OF CU-FT	(3) GROSS OIL & GAS SALES THOUSANDS OF $	(4) ROYALTY EXPENSE THOUSANDS OF $	(5) ADVALOREM & STATE TAXES THOUSANDS OF $	(6) OPERATING EXPENSES THOUSANDS OF $	(7) ADJUSTED GROSS INCOME THOUSANDS OF $	(8) TOTAL INVESTED CAPITAL THOUSANDS OF $
1964	105930	131353	381727	47716	21811	31626	280574	3110000
1965	211860	262707	763455	95432	43622	63252	561149	0
1966	211860	262706	763454	95432	43622	63252	561149	0
1967	211860	262706	763455	95431	43622	63252	561149	0
1968	211860	262707	763454	95432	43621	63252	561149	0
1969	211860	262706	763454	95432	43622	63252	561148	365000
1970	211860	262707	763455	95432	43622	63252	561149	0
1971	208795	258905	752408	94051	42991	63252	552114	0
1972	186380	233592	678845	84855	38787	63252	491951	0
1973	167407	207584	603263	75408	34469	63252	430133	0
1974	148767	184472	536095	67012	30632	63252	375200	0
1975	132204	163932	476406	59551	27220	63252	326383	0
1976	117484	145680	423363	52920	24190	63252	283001	0
1977	104403	129460	376226	47029	21497	63252	244449	0
1978	92779	115047	334337	41792	19103	63252	210190	0
1979	82449	102236	297112	37139	16976	63252	179744	0
1980	73269	90854	264031	33003	15086	63252	152689	0
1981	65112	60738	234634	29330	13407	63252	128647	0
1982	57862	71749	208510	26063	11913	63252	107280	0
1983	51419	63760	185294	23162	10588	63252	88293	0
SUB-TOTAL	2867420	3555601	10332977	1291623	590400	1233414	7217541	3475000
REMAINING 6.58 YRS	221580	274759	798481	99810	45623	415993	237055	0
TOTAL	3089000	3830360	11131458	1391433	636023	1649407	7454596	3475000

TIME YEARS	(9) INTANGIBLE DRILLING COSTS THOUSANDS OF $	(10) DEPLETION ALLOWANCE THOUSANDS OF $	(11) DEPRE-CIATION THOUSANDS OF $	(12) TAXABLE INCOME THOUSANDS OF $	(13) INVEST-MENT TAX CREDITS THOUSANDS OF $	(14) FEDERAL INCOME TAXES THOUSANDS OF $	(15) AFTER TAX NET INCOME THOUSANDS OF $	(16) NET CASH FLOW THOUSANDS OF $	(17) NET CASH FLOW DISC. 15% THOUSANDS OF $
1964	1885963	18895	23080	-1647382	25	-823716	1104291	-2005708	-1870332
1965	0	171710	46159	343278	47086	124553	436595	436594	354022
1966	0	171711	46159	343280	0	171640	389509	389509	274646
1967	0	171710	46159	343279	0	171639	389509	389509	238823
1968	0	171710	46159	343280	0	171640	389509	389509	207671
1969	269005	118231	55662	118230	6720	52396	508753	143753	66647
1970	0	171710	55662	333757	0	166878	394271	394271	158949
1971	0	169226	54876	328012	0	164006	388108	388108	136057
1972	0	152681	49511	289759	0	144879	347071	347071	105800
1973	0	135681	43999	250454	0	125228	304907	304907	80823
1974	0	120574	39100	215526	0	107763	267437	267437	61645
1975	0	107150	34746	184487	0	92243	234139	234139	46930
1976	0	95219	30878	156903	0	78452	204549	204549	35651
1977	0	84618	27439	132392	0	66196	178254	178254	27016
1978	0	75196	24385	110608	0	55304	154885	154885	20412
1979	0	66824	21670	91251	0	45625	134119	134119	15370
1980	0	59384	19257	74049	0	37025	115665	115665	11526
1981	0	52772	17113	58761	0	29380	99266	99266	8602
1982	0	46037	15207	46037	0	23018	84262	84262	6349
1983	0	37369	13514	37389	0	18695	69598	69598	4560
SUB-TOTAL	2154988	2198428	710775	2153350	53831	1022844	6194697	2719698	-8833
REMAINING 6.58 YRS	0	89409	58237	89409	0	44705	192350	192350	8833
TOTAL	2154988	2287837	769012	2242759	53831	1067549	6387047	2912048	0

GROSS OIL PRICE	$ 3.32 / BBL		ROYALTY INTEREST	12.50 %
GROSS GAS PRICE	$ .231 / THOUSAND CU-FT		FEDERAL INCOME TAX RATE	50.00 %
TOTAL RESERVE LIFE	26.58 YEARS		ADVALOREM AND STATE TAX RATE	6.53 %
LEASEHOLD INVESTMENT (000)	$ 551000.			

TABLE 17

COST OF NEW OIL
RESERVES AOOEO IN 1965
TOTAL UNITEO STATES

TIME YEARS	(1) GROSS OIL PROOUCTION THOUSANOS OF BBLS	(2) GROSS GAS PROOUCTION MILLIONS OF CU-FT	(3) GROSS OIL & GAS SALES THOUSANDS OF $	(4) ROYALTY EXPENSE THOUSANOS OF $	(5) AOVALOREM & STATE TAXES THOUSANOS OF $	(6) OPERATING EXPENSES THOUSANOS OF $	(7) AOJUSTED GROSS INCOME THOUSANOS OF $	(8) TOTAL INVESTEO CAPITAL THOUSANOS OF $
1965	75888	94101	326485	40811	18740	29604	237331	2825000
1966	151776	188202	652971	81621	37481	59208	474661	0
1967	151776	188203	652971	81621	37480	59208	474661	0
1968	151776	188202	652971	81622	37481	59208	474661	0
1969	151776	188202	652971	81621	37480	59208	474661	0
1970	151776	188202	652971	81622	37481	59208	474661	262000
1971	151776	188203	652971	81621	37480	59208	474661	0
1972	149606	185511	643635	80454	36945	59208	467027	0
1973	135145	167580	581421	72678	33374	59208	416162	0
1974	120268	149132	517418	64677	29699	59208	363834	0
1975	107029	132716	460461	57558	26431	59208	317265	0
1976	95248	118107	409774	51221	23521	59208	275822	0
1977	84762	105106	364665	45584	20932	59208	238943	0
1978	75432	93535	324524	40565	18627	59208	206122	0
1979	67126	83239	288799	36100	16577	59208	176915	0
1980	59739	74077	257009	32126	14753	59208	150922	0
1981	53163	65922	228717	28590	13128	59208	127791	0
1982	47311	58665	203540	25442	11683	59208	107206	0
1983	42103	52207	181134	22642	10397	59208	88888	0
1984	37468	46460	161195	20149	9253	59208	72585	0
SUB-TOTAL	2060946	2555573	8866603	1108326	508943	1154556	6094778	3087000
REMAINING 6.03 YRS	153054	189788	658472	82309	37796	357302	181065	0
TOTAL	2214000	2745361	9525075	1190635	546739	1511858	6275843	3087000

TIME YEARS	(9) INTANGIBLE DRILLING COSTS THOUSANDS OF $	(10) DEPLETION ALLOWANCE THOUSANOS OF $	(11) DEPRE-CIATION THOUSANDS OF $	(12) TAXABLE INCOME THOUSANOS OF $	(13) INVEST-MENT TAX CREDITS THOUSANDS OF $	(14) FEOERAL INCOME TAXES THOUSANDS OF $	(15) AFTER TAX NET INCOME THOUSANDS OF $	(16) NET CASH FLOW THOUSANOS OF $	(17) NET CASH FLOW DISC. 15% THOUSANDS OF $
1965	1902147	8843	22789	-1696448	25	-848248	1085580	-1739419	-1622017
1966	0	146814	45577	282269	46515	94619	380041	380040	308165
1967	0	146814	45578	282269	0	141135	333526	333526	235172
1968	0	146814	45577	282270	0	141134	333526	333526	204497
1969	0	146814	45576	282269	0	141135	333527	333527	177824
1970	194142	114107	52305	114108	4750	52304	422357	160357	74345
1971	0	146814	52304	275542	0	137771	336890	336890	135816
1972	0	144715	51557	270756	0	135378	331650	331650	116264
1973	0	130727	46573	238862	0	119431	296731	296731	90455
1974	0	116336	41447	206050	0	103025	260808	260808	69134
1975	0	103530	36884	176851	0	88425	228839	228839	52747
1976	0	92134	32824	150866	0	75433	200390	200390	40166
1977	0	81991	29211	127740	0	63870	175073	175073	30513
1978	0	72966	25995	107161	0	53581	152541	152541	23110
1979	0	64934	23133	88848	0	44424	132491	132491	17461
1980	0	57786	20587	72549	0	36274	114648	114648	13130
1981	0	51424	18321	58046	0	29023	98768	98768	9842
1982	0	45451	16304	45451	0	22726	84481	84481	7321
1983	0	37190	14510	37189	0	18594	70293	70293	5297
1984	0	29836	12912	29836	0	14918	57667	57667	3778
SUB-TOTAL	2096289	1886040	679966	1432484	51290	664952	5429827	2342827	-6962
REMAINING 6.03 YRS	0	64160	52745	64160	0	32080	148984	148984	6962
TOTAL	2096289	1950200	732711	1496644	51290	697032	5578811	2491811	0

GROSS OIL PRICE $ 4.01 / BBL
GROSS GAS PRICE $ .234 / THOUSANO CU-FT
TOTAL RESERVE LIFE 26.03 YEARS
LEASEHOLD INVESTMENT (000) $ 258000.

ROYALTY INTEREST 12.50 %
FEOERAL INCOME TAX RATE 50.00 %
AOVALOREM ANO STATE TAX RATE 6.56 %

TABLE 18

COST OF NEW OIL
RESERVES ADDED IN 1966
TOTAL UNITED STATES

TIME YEARS	(1) GROSS OIL PRODUCTION THOUSANDS OF BBLS	(2) GROSS GAS PRODUCTION MILLIONS OF CU-FT	(3) GROSS OIL & GAS SALES THOUSANDS OF $	(4) ROYALTY EXPENSE THOUSANDS OF $	(5) ADVALOREM & STATE TAXES THOUSANDS OF $	(6) OPERATING EXPENSES THOUSANDS OF $	(7) ADJUSTED GROSS INCOME THOUSANDS OF $	(8) TOTAL INVESTED CAPITAL THOUSANDS OF $
1966	67482	87794	340299	42537	19116	27906	250740	2902000
1967	134964	175588	680599	85075	38233	55812	501479	0
1968	134964	175588	680598	85075	38233	55812	501479	0
1969	134964	175589	680599	85075	38232	55812	501479	0
1970	134964	175588	680598	85075	38233	55812	501479	0
1971	134964	175588	680598	85074	36232	55812	501479	233000
1972	134964	175588	680599	85075	38233	55812	501479	0
1973	133011	173048	670750	83844	37679	55812	493415	0
1974	120006	156127	605168	75646	33996	55812	439714	0
1975	106644	138744	537785	67223	30210	55812	384540	0
1976	94769	123295	477905	59738	26846	55812	335509	0
1977	84218	109567	424693	53087	23857	55812	291937	0
1978	74840	97367	377404	47175	21201	55812	253216	0
1979	66507	86525	335383	41923	18840	55812	218807	0
1980	59102	76892	298038	37255	16742	55812	188230	0
1981	52520	68329	264854	33107	14878	55812	161057	0
1982	46673	60722	235363	29420	13222	55812	136909	0
1983	41477	53960	209157	26145	11749	55812	115451	0
1984	36858	47953	185868	23233	10442	55812	96381	0
1985	32754	42613	165172	20647	9278	55812	79435	0
SUB-TOTAL	1826645	2376465	9211429	1151429	517452	1088334	6454215	3135000
REMAINING 6.66 YRS	142355	185204	717873	89734	40327	371855	215957	0
TOTAL	1969000	2561669	9929302	1241163	557779	1460189	6670172	3135000

TIME YEARS	(9) INTANGIBLE DRILLING COSTS THOUSANDS OF $	(10) DEPLETION ALLOWANCE THOUSANDS OF $	(11) DEPRE-CIATION THOUSANDS OF $	(12) TAXABLE INCOME THOUSANDS OF $	(13) INVEST-MENT TAX CREDITS THOUSANDS OF $	(14) FEDERAL INCOME TAXES THOUSANDS OF $	(15) AFTER TAX NET INCOME THOUSANDS OF $	(16) NET CASH FLOW THOUSANDS OF $	(17) NET CASH FLOW DISC. 15% THOUSANDS OF $
1966	1839684	12612	23796	-1625351	25	-812700	1063441	-1838558	-1714464
1967	0	153255	47591	300631	37676	112639	388839	388838	315298
1968	0	153255	47592	300633	0	150316	351163	351163	247608
1969	0	153255	47591	300632	0	150316	351162	351162	215311
1970	0	153255	47592	300633	0	150316	351163	351163	187226
1971	169158	139201	53919	139200	3467	66134	435345	202345	93812
1972	0	153255	53919	294305	0	147153	354327	354327	142846
1973	0	151038	53140	289239	0	144619	348796	348796	122275
1974	0	136269	47943	255501	0	127750	311964	311964	95098
1975	0	121097	42605	220838	0	110419	274121	274121	72663
1976	0	107613	37861	190034	0	95018	240491	240491	55433
1977	0	95631	33646	162660	0	81330	210607	210607	42213
1978	0	84983	29899	138335	0	69167	184049	184049	32079
1979	0	75520	26570	116717	0	58358	160449	160449	24317
1980	0	67112	23612	97506	0	48754	139477	139477	18382
1981	0	59639	20983	80435	0	40217	120839	120839	13848
1982	0	52998	18646	65265	0	32633	104277	104277	10391
1983	0	47097	16570	51783	0	25891	89559	89559	7761
1984	0	40828	14725	40828	0	20414	75967	75967	5724
1985	0	33175	13086	33175	0	16588	62848	62848	4118
SUB-TOTAL	2008842	1991088	701286	1752999	41168	835331	5618884	2483884	-8061
REMAINING 6.66 YRS	0	79543	56872	79543	0	39771	176185	176185	8061
TOTAL	2008842	2070631	758158	1832542	41168	875102	5795069	2660069	0

GROSS OIL PRICE $ 4.74 / BBL
GROSS GAS PRICE $ .236 / THOUSAND CU-FT
TOTAL RESERVE LIFE 26.66 YEARS
LEASEHOLD INVESTMENT (000) $ 368000.

ROYALTY INTEREST 12.50 %
FEDERAL INCOME TAX RATE 50.00 %
ADVALOREM AND STATE TAX RATE 6.42 %

TABLE 19

COST OF NEW OIL
RESERVES ADDED IN 1967
TOTAL UNITED STATES

TIME YEARS	(1) GROSS OIL PRODUCTION THOUSANDS OF BBLS	(2) GROSS GAS PRODUCTION MILLIONS OF CU-FT	(3) GROSS OIL & GAS SALES THOUSANDS OF $	(4) ROYALTY EXPENSE THOUSANDS OF $	(5) ADVALOREM & STATE TAXES THOUSANDS OF $	(6) OPERATING EXPENSES THOUSANDS OF $	(7) ADJUSTED GROSS INCOME THOUSANDS OF $	(8) TOTAL INVESTED CAPITAL THOUSANDS OF $
1967	63672	65455	333621	41703	19354	26802	245762	2913000
1968	127344	130909	667242	83405	38709	53604	491525	0
1969	127344	130910	667242	83405	38708	53604	491524	0
1970	127344	130910	667243	83405	38708	53604	491525	0
1971	127344	130909	667242	83406	38709	53604	491524	0
1972	127344	130910	667242	83405	38708	53604	491525	219000
1973	127344	130910	667242	83405	38709	53604	491524	0
1974	125496	129009	657557	82195	38146	53604	483612	0
1975	113187	116357	593068	74133	34405	53604	430926	0
1976	100547	103362	526832	65854	30563	53604	376811	0
1977	89317	91818	467993	58500	27150	53604	328740	0
1978	79342	81563	415726	51965	24117	53604	286039	0
1979	70480	72454	369296	46162	21424	53604	248106	0
1980	62609	64362	328051	41007	19031	53604	214410	0
1981	55617	57174	291413	36426	16905	53604	184477	0
1982	49405	50789	258867	32359	15018	53604	157887	0
1983	43887	45116	229956	28744	13340	53604	134267	0
1984	38986	40077	204273	25534	11851	53604	113284	0
1985	34632	35601	181459	22683	10527	53604	94646	0
1986	30764	31626	161193	20149	9351	53604	78089	0
SUB-TOTAL	1722005	1770221	9022758	1127845	523433	1045278	6326202	3132000
REMAINING 6.77 YRS	134995	138775	707334	88416	41034	363140	214743	0
TOTAL	1857000	1908996	9730092	1216261	564467	1408418	6540945	3132000

TIME YEARS	(9) INTANGIBLE DRILLING COSTS THOUSANDS OF $	(10) DEPLETION ALLOWANCE THOUSANDS OF $	(11) DEPRE-CIATION THOUSANDS OF $	(12) TAXABLE INCOME THOUSANDS OF $	(13) INVEST-MENT TAX CREDITS THOUSANDS OF $	(14) FEDERAL INCOME TAXES THOUSANDS OF $	(15) AFTER TAX NET INCOME THOUSANDS OF $	(16) NET CASH FLOW THOUSANDS OF $	(17) NET CASH FLOW DISC. 15% THOUSANDS OF $
1967	1927170	9978	23824	-1715208	25	-857629	1103392	-1809607	-1687467
1968	0	149910	47648	293965	39580	107402	384122	384121	311473
1969	0	149910	47648	293966	0	146983	344541	344541	242939
1970	0	149911	47648	293966	0	146983	344542	344542	211251
1971	0	149910	47648	293966	0	146983	344541	344541	183697
1972	160965	138578	53404	138578	3308	65981	425544	206544	95757
1973	0	149910	53404	288210	0	144105	347419	347419	140062
1974	0	147734	52629	283249	0	141624	341988	341988	119888
1975	0	133246	47468	250212	0	125107	305819	305819	93225
1976	0	118364	42166	216281	0	108140	268670	268670	71218
1977	0	105145	37456	186139	0	93070	235672	235672	54323
1976	0	93402	33274	159364	0	79681	206356	206356	41361
1979	0	82970	29557	135578	0	67790	180317	180317	31428
1980	0	73704	26256	114450	0	57225	157185	157185	23822
1981	0	65472	23324	95681	0	47840	136637	136637	18008
1982	0	58160	20719	79008	0	39504	118383	118383	13566
1983	0	51665	16405	64197	0	32099	102168	102168	10181
1984	0	45894	16349	51041	0	25520	87764	87764	7606
1985	0	40061	14524	40061	0	20031	74615	74615	5622
1986	0	32594	12901	32594	0	16297	61792	61792	4049
SUB-TOTAL	2088135	1946518	696252	1595298	42914	754736	5571467	2439467	-7991
REMAINING 6.77 YRS	0	79065	56613	79065	0	39532	175211	175211	7991
TOTAL	2088135	2025583	752865	1674363	42914	794268	5746678	2614678	0

GROSS OIL PRICE	$ 4.99 / BBL	ROYALTY INTEREST	12.50 %
GROSS GAS PRICE	$ .240 / THOUSAND CU-FT	FEDERAL INCOME TAX RATE	50.00 %
TOTAL RESERVE LIFE	26.77 YEARS	ADVALOREM AND STATE TAX RATE	6.63 %
LEASEHOLD INVESTMENT (000)	$ 291000.		

TABLE 20

COST OF NEW OIL
RESERVES ADDED IN 1968
TOTAL UNITED STATES

TIME YEARS	(1) GROSS OIL PRODUCTION THOUSANDS OF BBLS	(2) GROSS GAS PRODUCTION MILLIONS OF CU-FT	(3) GROSS OIL & GAS SALES THOUSANDS OF $	(4) ROYALTY EXPENSE THOUSANDS OF $	(5) ADVALOREM & STATE TAXES THOUSANDS OF $	(6) OPERATING EXPENSES THOUSANDS OF $	(7) ADJUSTED GROSS INCOME THOUSANDS OF $	(8) TOTAL INVESTED CAPITAL THOUSANDS OF $
1968	68070	77328	367861	45983	21534	27222	273123	3211000
1969	136140	154655	735723	91965	43067	54444	546246	0
1970	136140	154655	735722	91965	43067	54444	546245	0
1971	136140	154655	735723	91966	43068	54444	546246	0
1972	136140	154655	735722	91965	43067	54444	546246	0
1973	136140	154655	735722	91965	43067	54444	546246	235000
1974	136140	154655	735723	91965	43068	54444	546246	0
1975	134148	152392	724957	90620	42437	54444	537456	0
1976	120889	137330	653304	81663	38243	54444	478954	0
1977	107283	121873	579774	72472	33938	54444	418920	0
1978	95208	108156	514519	64315	30119	54444	365642	0
1979	84492	95984	456610	57076	26729	54444	318361	0
1980	74983	85180	405218	50652	23720	54444	276401	0
1981	66543	75593	359611	44952	21051	54444	239164	0
1982	59054	67085	319136	39892	18681	54444	206119	0
1983	52467	59535	283216	35402	16579	54444	176792	0
1984	46509	52834	251341	31417	14713	54444	150766	0
1985	41274	46887	223052	27882	13057	54444	127669	0
1986	36628	41610	197947	24743	11587	54444	107172	0
1987	32506	36927	175667	21959	10283	54444	88983	0
SUB-TOTAL	1836834	2086644	9926548	1240818	581076	1061658	7042996	3446000
REMAINING 7.30 YRS	149166	169452	806116	100764	47188	397707	260456	0
TOTAL	1986000	2256096	10732664	1341582	628264	1459365	7303452	3446000

TIME YEARS	(9) INTANGIBLE DRILLING COSTS THOUSANDS OF $	(10) DEPLETION ALLOWANCE THOUSANDS OF $	(11) DEPRE-CIATION THOUSANDS OF $	(12) TAXABLE INCOME THOUSANDS OF $	(13) INVEST-MENT TAX CREDITS THOUSANDS OF $	(14) FEDERAL INCOME TAXES THOUSANDS OF $	(15) AFTER TAX NET INCOME THOUSANDS OF $	(16) NET CASH FLOW THOUSANDS OF $	(17) NET CASH FLOW DISC. 15% THOUSANDS OF $
1968	2093616	13667	24691	-1856790	25	-929420	1202544	-2008455	-1072894
1969	0	165190	49362	331673	50402	115434	430810	430809	349332
1970	0	165190	49383	331673	0	165837	380409	380409	268229
1971	0	165189	49382	331674	0	165837	380409	380409	233243
1972	0	165190	49382	331674	0	165837	380409	380409	202820
1973	174840	158030	55346	158030	4211	74804	471442	236442	109619
1974	0	165190	55346	325711	0	162855	383390	383390	154563
1975	0	162772	54535	320147	0	160074	377383	377383	132296
1976	0	146685	49146	283124	0	141562	337392	337392	102850
1977	0	130175	43614	245130	0	122565	296354	296354	78556
1978	0	115523	38706	211413	0	105707	259936	259936	59916
1979	0	102522	34349	181491	0	90745	227616	227616	45622
1980	0	90982	30483	154936	0	77468	198933	198933	34672
1981	0	80742	27052	131370	0	65685	173480	173480	26293
1982	0	71655	24006	110456	0	55226	150690	150890	19885
1983	0	63590	21305	91896	0	45948	130844	130843	14995
1984	0	56433	18908	75426	0	37713	113053	113054	11266
1985	0	50081	16779	60809	0	30404	97265	97265	8428
1986	0	44444	14891	47837	0	23919	83253	83253	6274
1987	0	37884	13215	37884	0	18942	70041	70041	4589
SUB-TOTAL	2268456	2151074	719903	1903564	54638	897143	6145853	2699853	-9446
REMAINING 7.30 YRS	0	99907	60641	99907	0	49954	210502	210502	9446
TOTAL	2268456	2250981	780544	2003471	54638	947097	6356355	2910355	0

GROSS OIL PRICE $ 5.12 / BBL
GROSS GAS PRICE $ .246 / THOUSAND CU-FT
TOTAL RESERVE LIFE 27.30 YEARS
LEASEHOLD INVESTMENT (000) $ 397000.

ROYALTY INTEREST 12.50 %
FEDERAL INCOME TAX RATE 50.00 %
ADVALOREM AND STATE TAX RATE 6.69 %

LA RUE, MOORE & SCHAFER

TABLE 21

COST OF NEW OIL
RESERVES ADDED IN 1969
TOTAL UNITED STATES

TIME YEARS	(1) GROSS OIL PRODUCTION THOUSANDS OF BBLS	(2) GROSS GAS PRODUCTION MILLIONS OF CU-FT	(3) GROSS OIL & GAS SALES THOUSANDS OF $	(4) ROYALTY EXPENSE THOUSANDS OF $	(5) ADVALOREM & STATE TAXES THOUSANDS OF $	(6) OPERATING EXPENSES THOUSANDS OF $	(7) ADJUSTED GROSS INCOME THOUSANDS OF $	(8) TOTAL INVESTED CAPITAL THOUSANDS OF $
1969	51714	65211	379132	47391	21762	27354	282624	3228000
1970	103428	130423	758264	94783	43525	54708	565249	0
1971	103426	130423	758264	94783	43524	54708	565248	0
1972	103428	130422	758263	94783	43524	54708	565249	0
1973	103426	130423	758284	94783	43525	54708	565248	0
1974	103428	130423	758264	94783	43524	54708	565249	178000
1975	103428	130423	758264	94783	43524	54708	565248	0
1976	101911	128509	747143	93393	42886	54708	556156	0
1977	91816	115781	673134	84142	38638	54708	495647	0
1978	81460	102720	597205	74651	34280	54708	433567	0
1979	72271	91134	529841	66230	30413	54708	378490	0
1980	64118	80853	470076	58759	26982	54708	329626	0
1981	56887	71734	417051	52132	23939	54708	286273	0
1982	50469	63642	370009	46251	21238	54708	247811	0
1983	44777	56464	328272	41034	18843	54708	213687	0
1984	39726	50094	291243	36405	16717	54708	183413	0
1985	35245	44444	256392	32299	14832	54708	156553	0
1986	31269	39430	229245	28656	13159	54708	132722	0
1987	27742	34983	203386	25423	11674	54708	111581	0
1988	24613	31037	180445	22556	10358	54708	92824	0
SUB-TOTAL	1394586	1758573	10224156	1278019	586867	1066806	7292465	3406000
REMAINING 7.47 YRS	114414	144276	838807	104851	48147	408690	277118	0
TOTAL	1509000	1902849	11062963	1382870	635014	1475496	7569583	3406000

TIME YEARS	(9) INTANGIBLE DRILLING COSTS THOUSANDS OF $	(10) DEPLETION ALLOWANCE THOUSANDS OF $	(11) DEPRE-CIATION THOUSANDS OF $	(12) TAXABLE INCOME THOUSANDS OF $	(13) INVEST-MENT TAX CREDITS THOUSANDS OF $	(14) FEDERAL INCOME TAXES THOUSANDS OF $	(15) AFTER TAX NET INCOME THOUSANDS OF $	(16) NET CASH FLOW THOUSANDS OF $	(17) NET CASH FLOW DISC. 15% THOUSANDS OF $
1969	1980576	18403	24346	-1740700	25	-870375	1153000	-2074999	-1934947
1970	0	170468	48693	346066	34999	138034	427214	427213	346416
1971	0	170468	48693	346068	0	173034	392214	392214	276553
1972	0	170488	40893	346067	0	173034	392215	392215	240482
1973	0	170468	48693	346068	0	173033	392215	392215	209114
1974	131008	170486	53351	210402	2317	102885	462364	284364	131837
1975	0	170468	53350	341410	0	170705	394544	394544	159059
1976	0	167988	52508	335600	0	167800	388355	388355	136143
1977	0	151348	47361	296939	0	148469	347178	347178	105833
1978	0	134275	42018	257272	0	128637	304930	304930	80830
1979	0	119130	37279	222082	0	111041	267449	267449	61647
1980	0	105691	33074	190860	0	95430	234196	234196	46941
1981	0	93770	29343	163161	0	81580	204693	204893	35677
1982	0	83193	26033	138585	0	69292	178519	178519	27056
1983	0	73809	23097	116782	0	58391	155296	155296	20466
1984	0	65463	20492	97437	0	48719	134694	134694	15436
1985	0	58097	18180	80276	0	40138	116414	116414	11801
1986	0	51543	18129	85050	0	32525	100198	100198	8682
1987	0	45729	14310	51542	0	25771	85810	85810	6466
1988	0	40064	12696	40084	0	20032	72792	72792	4770
SUB-TOTAL	2111564	2231451	898399	2251031	37340	1088175	6204290	2798290	-9938
REMAINING 7.47 YRS	0	109051	59017	109050	0	54525	222593	222593	9938
TOTAL	2111584	2340502	757416	2360081	37340	1142700	6426883	3020883	0

GROSS OIL PRICE $ 7.01 / BBL
GROSS GAS PRICE $ .251 / THOUSAND CU-FT
TOTAL RESERVE LIFE 27.47 YEARS
LEASEHOLD INVESTMENT (000) $ 537000.

ROYALTY INTEREST 12.50 %
FEDERAL INCOME TAX RATE 50.00 %
ADVALOREM AND STATE TAX RATE 6.56 %

TABLE 22

COST OF NEW OIL
RESERVES ADDED IN 1970
TOTAL UNITED STATES (a)

TIME YEARS	(1) GROSS OIL PRODUCTION THOUSANDS OF BBLS	(2) GROSS GAS PRODUCTION MILLIONS OF CU-FT	(3) GROSS OIL & GAS SALES THOUSANDS OF $	(4) ROYALTY EXPENSE THOUSANDS OF $	(5) ADVALOREM & STATE TAXES THOUSANDS OF $	(6) OPERATING EXPENSES THOUSANDS OF $	(7) ADJUSTED GROSS INCOME THOUSANDS OF $	(8) TOTAL INVESTED CAPITAL THOUSANDS OF $
1970	60000	74400	454015	56752	26180	29874	341210	3383000
1971	120000	148800	908031	113504	52359	59748	682419	0
1972	120000	148800	908030	113504	52359	59748	682420	0
1973	120000	146800	908031	113503	52360	59748	682419	0
1974	120000	148800	908031	113504	52359	59748	682420	0
1975	120000	148800	908030	113504	52359	59748	682419	207000
1976	120000	146800	908031	113504	52360	59748	682419	0
1977	116223	146597	894586	111823	51584	59748	671431	0
1978	106405	131942	805156	100645	46427	59748	598337	0
1979	94292	116922	713503	89188	41142	59748	523424	0
1980	83559	103613	632283	79035	36459	59748	457041	0
1981	74047	91818	560308	70038	32309	59748	398213	0
1982	65618	81367	496527	62066	28631	59748	346082	0
1983	58149	72104	440005	55001	25372	59748	299885	0
1984	51529	63896	389919	48740	22484	59748	258946	0
1985	45664	56623	345532	43191	19924	59748	222669	0
1986	40465	50178	306200	38275	17656	59748	190521	0
1987	35859	44465	271344	33918	15646	59748	162031	0
1988	31778	39404	240456	30057	13866	59748	136786	0
1989	28160	34918	213084	26636	12287	59748	114414	0
SUB-TOTAL	1613748	2001047	12211102	1526388	704123	1165086	8815506	3590000
REMAINING 8.04 YRS	136252	168953	1031012	128876	59450	480371	362313	0
TOTAL	1750000	2170000	13242114	1655264	763573	1645457	9177819	3590000

TIME YEARS	(9) INTANGIBLE DRILLING COSTS THOUSANDS OF $	(10) DEPLETION ALLOWANCE THOUSANDS OF $	(11) DEPRE-CIATION THOUSANDS OF $	(12) TAXABLE INCOME THOUSANDS OF $	(13) INVEST-MENT TAX CREDITS THOUSANDS OF $	(14) FEDERAL INCOME TAXES THOUSANDS OF $	(15) AFTER TAX NET INCOME THOUSANDS OF $	(16) NET CASH FLOW THOUSANDS OF $	(17) NET CASH FLOW DISC. 15% THOUSANDS OF $
1970	1739232	34526	21832	-1454379	0	-727189	1068400	-2314599	-2158375
1971	0	163277	43664	475477	0	237738	444680	444679	360579
1972	0	163276	43664	475479	0	237740	444680	444680	313547
1973	0	163277	43664	475479	0	237739	444680	444680	272650
1974	0	163277	43664	475478	0	237739	444681	444681	237087
1975	151524	163277	49166	318453	0	159226	523193	316193	146593
1976	0	163277	49166	469977	0	234989	447431	447431	180381
1977	0	160859	46438	462133	0	231067	440364	440364	154375
1978	0	144779	43596	409962	0	204981	393355	393355	119910
1979	0	128298	36633	356494	0	178247	345178	345178	91498
1980	0	113693	34235	309112	0	154555	302485	302485	69723
1981	0	100752	30338	267123	0	133562	264651	264651	53046
1982	0	89262	26885	229915	0	114957	231124	231124	40283
1983	0	79119	23624	196941	0	98471	201415	201415	30526
1984	0	70113	21113	167722	0	83861	175086	175086	23074
1985	0	62132	16709	141828	0	70914	151754	151754	17391
1986	0	55059	16579	118882	0	59441	131080	131080	13063
1987	0	46791	14692	98548	0	49274	112758	112758	9771
1988	0	43238	13020	80529	0	40264	96521	96521	7273
1989	0	38316	11537	64560	0	32281	82133	82133	5381
SUB-TOTAL	1690756	2148617	636419	4139713	0	2069856	6745649	3155649	-12224
REMAINING 8.04 YRS	0	141078	55825	165411	0	82705	279609	279609	12224
TOTAL	1690756	2289695	692244	4305124	0	2152561	7025258	3435258	0

GROSS OIL PRICE $ 7.25 / BBL
GROSS GAS PRICE $ .257 / THOUSAND CU-FT
TOTAL RESERVE LIFE 28.04 YEARS
LEASEHOLD INVESTMENT (000) $1007000.

ROYALTY INTEREST 12.50 %
FEDERAL INCOME TAX RATE 50.00 %
ADVALOREM AND STATE TAX RATE 6.59 %

FOOTNOTE:

(a) Excludes Prudhoe Bay field in Alaska.

TABLE 23

COST OF NEW OIL
RESERVES ADDED IN 1971
TOTAL UNITED STATES

TIME YEARS	(1) GROSS OIL PRODUCTION THOUSANDS OF BBLS	(2) GROSS GAS PRODUCTION MILLIONS OF CU-FT	(3) GROSS OIL & GAS SALES THOUSANDS OF $	(4) ROYALTY EXPENSE THOUSANDS OF $	(5) ADVALOREM & STATE TAXES THOUSANDS OF $	(6) OPERATING EXPENSES THOUSANDS OF $	(7) ADJUSTED GROSS INCOME THOUSANDS OF $	(8) TOTAL INVESTED CAPITAL THOUSANDS OF $
1971	43038	51043	368138	46017	20584	28902	272635	2884000
1972	66076	102086	736276	92035	41167	57804	545271	0
1973	86076	102086	736277	92034	41167	57804	545271	0
1974	86076	102066	736276	92035	41167	57804	545270	0
1975	86076	102087	736276	92034	41167	57804	545271	0
1976	86076	102086	736277	92035	41167	57804	545271	148000
1977	86076	102086	736276	92034	41167	57804	545271	0
1978	84823	100600	725558	90695	40568	57804	536491	0
1979	76481	90707	654206	81776	36576	57804	478048	0
1980	67917	80548	580941	72618	32482	57804	418038	0
1981	60310	71528	515882	64485	26844	57804	364748	0
1982	53556	63518	458106	57263	25614	57804	317427	0
1983	47556	56404	406805	50851	22745	57804	275405	0
1984	42233	50088	361247	45156	20199	57804	238089	0
1985	37503	44478	320792	40099	17936	57804	204952	0
1986	33303	39498	284666	35608	15927	57804	175526	0
1987	29573	35074	252964	31621	14144	57804	149396	0
1988	26261	31146	224634	28079	12560	57804	126191	0
1989	23321	27658	199478	24935	11154	57804	105586	0
1990	20706	24560	177139	22142	9904	57804	87288	0
SUB-TOTAL	1163041	1379367	9948415	1243552	556241	1127178	7021445	3032000
REMAINING 6.91 YRS	91959	109063	786595	98324	43980	399569	244721	0
TOTAL	1255000	1488430	10735010	1341876	600221	1526747	7266166	3032000

TIME YEARS	(9) INTANGIBLE DRILLING COSTS THOUSANDS OF $	(10) DEPLETION ALLOWANCE THOUSANDS OF $	(11) DEPRE-CIATION THOUSANDS OF $	(12) TAXABLE INCOME THOUSANDS OF $	(13) INVEST-MENT TAX CREDITS THOUSANDS OF $	(14) FEDERAL INCOME TAXES THOUSANDS OF $	(15) AFTER TAX NET INCOME THOUSANDS OF $	(16) NET CASH FLOW THOUSANDS OF $	(17) NET CASH FLOW DISC. 15% THOUSANDS OF $
1971	1641287	23146	19469	-1411267	25	-705658	978294	-1905705	-1777079
1972	0	132676	38937	373656	39715	147112	398158	398157	322855
1973	0	132677	38938	373656	0	186829	358442	358442	252740
1974	0	132676	38937	373657	0	186828	358442	358442	219774
1975	0	132677	38937	373657	0	186829	358443	358443	191108
1976	109964	132676	42711	259920	2662	127297	417973	269973	125165
1977	0	132677	42711	369883	0	184942	360329	360329	145266
1978	0	130745	42089	363658	0	181829	354663	354663	124332
1979	0	117687	37950	322210	0	161105	316942	316942	96610
1980	0	104685	33700	279653	0	139826	278212	278212	73747
1981	0	92962	29926	241861	0	120930	243818	243818	56200
1982	0	82550	26574	208301	0	104151	213276	213276	42748
1983	0	73306	23599	178501	0	89251	186154	186154	32446
1984	0	65097	20955	152037	0	76018	162071	162071	24563
1985	0	57806	18609	128537	0	64268	140684	140684	18540
1986	0	51333	16525	107668	0	53835	121691	121691	13946
1987	0	45584	14674	89136	0	44569	104827	104827	10446
1988	0	40479	13031	72682	0	36340	89851	89851	7786
1989	0	35946	11572	58068	0	29035	76552	76552	5769
1990	0	31920	10275	45092	0	22546	64741	64741	4242
SUB-TOTAL	1751251	1749506	560119	2960568	42403	1437882	5583563	2551563	-8790
REMAINING 6.91 YRS	0	96934	45630	102157	0	51078	193643	193643	8790
TOTAL	1751251	1846440	605749	3062725	42403	1488960	5777206	2745206	0

GROSS OIL PRICE $ 8.23 / BBL
GROSS GAS PRICE $ .273 / THOUSAND CU-FT
TOTAL RESERVE LIFE 26.91 YEARS
LEASEHOLD INVESTMENT (000) $ 675000.

ROYALTY INTEREST . 12.50 %
FEDERAL INCOME TAX RATE 50.00 %
ADVALOREM AND STATE TAX RATE 6.39 %

TABLE 24

COST OF NEW OIL
RESERVES ADOEO IN 1972
TOTAL UNITEO STATES

TIME YEARS	(1) GROSS OIL PRODUCTION THOUSANDS OF BBLS	(2) GROSS GAS PRODUCTION MILLIONS OF CU-FT	(3) GROSS OIL & GAS SALES THOUSANDS OF $	(4) ROYALTY EXPENSE THOUSANDS OF $	(5) AOVALOREM & STATE TAXES THOUSANDS OF $	(6) OPERATING EXPENSES THOUSANDS OF $	(7) AOJUSTED GROSS INCOME THOUSANDS OF $	(8) TOTAL INVESTED CAPITAL THOUSANDS OF $
1972	44262	60418	343472	42934	19084	28356	253098	2833000
1973	88524	120835	686943	85868	36168	56712	506195	0
1974	88524	120835	686943	85868	36169	56712	506195	0
1975	88524	120635	686944	85868	38166	56712	506195	0
1976	86524	120836	686943	85868	36168	56712	506195	0
1977	88524	120835	686943	85868	38169	56712	506195	153000
1976	86524	120835	686943	85867	38168	56712	506195	0
1979	87245	119090	677019	84628	37617	56712	498063	0
1980	76727	107462	610920	76365	33944	56712	443899	0
1961	69974	95515	542997	67874	30170	56712	388239	0
1982	62194	84895	482624	60328	26816	56712	338769	0
1963	55280	75456	428965	53621	23834	56712	294796	0
1964	49133	67067	381272	47659	21185	56712	255716	0
1985	43670	59610	338860	42360	18829	56712	220979	0
1986	38815	52962	301203	37650	16735	56712	190105	0
1967	34499	47092	267714	33465	14875	56712	162663	0
1968	30604	41656	237949	29743	13221	56712	138272	0
1989	27254	37202	211493	26437	11751	56712	116594	0
1990	24225	33066	187978	23497	10445	56712	97324	0
1991	21530	29389	167079	20885	9283	56712	80199	0
SUB-TOTAL	1198616	1636111	9301223	1162653	516799	1105884	6515887	2986000
REMAINING 0.64 YRS	93384	127469	724654	90582	40264	376308	217501	0
TOTAL	1292000	1763580	10025877	1253235	557063	1462192	6733388	2986000

TIME YEARS	(9) INTANGIBLE DRILLING COSTS THOUSANDS OF $	(10) DEPLETION ALLOWANCE THOUSANDS OF $	(11) DEPRE-CIATION THOUSANDS OF $	(12) TAXABLE INCOME THOUSANDS OF $	(13) INVEST-MENT TAX CREOITS THOUSANDS OF $	(14) FEDERAL INCOME TAXES THOUSANDS OF $	(15) AFTER TAX NET INCOME THOUSANDS OF $	(16) NET CASH FLOW THOUSANDS OF $	(17) NET CASH FLOW OISC. 15% THOUSANDS OF $
1972	1780716	13601	22449	-1563667	25	-781858	1034957	-1796042	-1676683
1973	0	123839	44898	337456	45845	122883	383311	383310	310816
1974	0	123840	44898	337458	0	168729	337466	337466	237950
1975	0	123839	44898	337457	0	168728	337467	337467	206913
1976	0	123640	44898	337458	0	168729	337466	337466	179925
1977	111643	123839	46976	221537	2681	107888	398307	245307	113729
1976	0	123640	40975	333381	0	166690	339505	339505	136871
1979	0	122050	48267	327744	0	163872	334190	334190	117154
1980	0	110135	43555	290210	0	145105	298795	298795	91084
1981	0	97889	38713	251637	0	125819	262421	262421	69562
1962	0	67006	34408	217355	0	108677	230091	230091	53036
1963	0	77332	30563	186883	0	93442	201356	201356	40359
1964	0	68734	27182	159799	0	79899	175817	175817	30643
1965	0	61092	24161	135727	0	67864	153115	153115	23206
1966	0	54300	21474	114331	0	57165	132940	132940	17520
1967	0	46263	19066	95314	0	47657	115006	115006	13180
1968	0	42896	16965	78412	0	39206	99066	99066	9872
1969	0	36127	15078	63388	0	31694	84900	84900	7357
1990	0	33886	13402	50034	0	25017	72307	72307	5448
1991	0	30121	11911	38167	0	19084	61115	61115	4005
SUB-TOTAL	1892559	1626471	644777	2350080	48751	1126290	5389598	2403598	-8053
REMAINING 0.64 YRS	0	82495	51664	83342	0	41670	175830	175830	8053
TOTAL	1892559	1710966	696441	2433422	48751	1167960	5565428	2579428	0

GROSS OIL PRICE $ 7.36 / BBL
GROSS GAS PRICE $ .293 / THOUSAND CU-FT
TOTAL RESERVE LIFE 26.64 YEARS
LEASEHOLD INVESTMENT (000) $ 397000.

ROYALTY INTEREST 12.50 %
FEDERAL INCOME TAX RATE 50.00 %
ADVALOREM ANO STATE TAX RATE 6.35 %

TABLE 25

COST OF NEW OIL
RESERVES ADDED IN 1973
TOTAL UNITED STATES

TIME YEARS	(1) GROSS OIL PRODUCTION THOUSANDS OF BBLS	(2) GROSS GAS PRODUCTION MILLIONS OF CU-FT	(3) GROSS OIL & GAS SALES THOUSANDS OF $	(4) ROYALTY EXPENSE THOUSANDS OF $	(5) ADVALOREM & STATE TAXES THOUSANDS OF $	(6) OPERATING EXPENSES THOUSANDS OF $	(7) ADJUSTED GROSS INCOME THOUSANDS OF $	(8) TOTAL INVESTED CAPITAL THOUSANDS OF $
1973	35646	49726	324021	40503	17380	27732	238407	2723000
1974	71292	99453	648043	81005	34759	55464	476814	0
1975	71292	99452	648043	81005	34760	55464	476814	0
1976	71292	99452	648043	81006	34759	55464	476815	0
1977	71292	99453	648043	81005	34759	55464	476814	0
1978	71292	99452	648043	81006	34760	55464	476814	123000
1979	71292	99452	648043	81005	34759	55464	476814	0
1980	70265	98020	638711	79839	34259	55464	469150	0
1961	63428	86481	570552	72069	30925	55464	418094	0
1962	56397	78675	512654	64081	27497	55464	365610	0
1963	50147	69955	455836	56980	24450	55464	318943	0
1964	44590	62203	405317	50665	21740	55464	277448	0
1965	39647	55308	360396	45049	19331	55464	240552	0
1966	35254	49178	320453	40057	17188	55464	207744	0
1967	31346	43729	284938	35617	15284	55464	178573	0
1968	27872	38881	253358	31670	13589	55464	152635	0
1969	24764	34573	225279	26160	12084	55464	129572	0
1990	22036	30741	200312	25039	10744	55464	109064	0
1991	19594	27334	178111	22263	9553	55464	90830	0
1992	17423	24304	156371	19797	8495	55464	74616	0
SUB-TOTAL	966181	1347822	8782566	1097820	471075	1081548	6132122	2846000
REMAINING 6.39 YRS	73819	102978	671014	83877	35991	354604	196542	0
TOTAL	1040000	1450800	9453580	1181697	507066	1436152	6328664	2846000

TIME YEARS	(9) INTANGIBLE DRILLING COSTS THOUSANDS OF $	(10) DEPLETION ALLOWANCE THOUSANDS OF $	(11) DEPRE-CIATION THOUSANDS OF $	(12) TAXABLE INCOME THOUSANDS OF $	(13) INVEST-MENT TAX CREDITS THOUSANDS OF $	(14) FEDERAL INCOME TAXES THOUSANDS OF $	(15) AFTER TAX NET INCOME THOUSANDS OF $	(16) NET CASH FLOW THOUSANDS OF $	(17) NET CASH FLOW DISC. 15% THOUSANDS OF $
1973	1764735	11037	21806	-1559171	25	-779610	1018018	-1704981	-1589903
1974	0	117101	43616	316096	44514	113534	363280	363279	294573
1975	0	117101	43616	316097	0	158048	318765	318765	224764
1976	0	117101	43616	316097	0	158049	318766	318766	195447
1977	0	117101	43616	316097	0	158048	318766	318766	169954
1976	90405	117102	40847	222461	2281	108949	367865	244865	113524
1979	0	117101	40647	312865	0	156433	320381	320381	129161
1980	0	115415	40172	307562	0	153781	315369	315369	110557
1981	0	104163	41679	272233	0	136116	281978	281978	85957
1982	0	92636	37060	235914	0	117957	247653	247653	65647
1963	0	82309	32953	203621	0	101811	217132	217132	50050
1964	0	73241	29300	174907	0	87453	189995	189995	38081
1965	0	65123	26053	149375	0	74688	165864	165864	28909
1966	0	57906	23166	126673	0	63336	144408	144408	21986
1967	0	51488	20598	106487	0	53244	125329	125329	16517
1966	0	45782	18315	88538	0	44269	108367	108366	12419
1969	0	40708	16266	72578	0	36289	93282	93283	9296
1990	0	36196	14480	58388	0	29194	79870	79870	6921
1991	0	32165	12876	45769	0	22884	67946	67945	5120
1992	0	28618	11448	34550	0	17275	57341	57342	3757
SUB-TOTAL	1855140	1539493	620352	2117137	46820	1011748	5120374	2274374	-7363
REMAINING 6.39 YRS	0	74017	48508	74017	0	37009	159533	159533	7363
TOTAL	1855140	1613510	668860	2191154	46820	1048757	5279907	2433907	0

GROSS OIL PRICE $ 8.70 / BBL
GROSS GAS PRICE $ .279 / THOUSAND CU-FT
TOTAL RESERVE LIFE 26.39 YEARS
LEASEHOLD INVESTMENT (000) $ 322000.

ROYALTY INTEREST 12.50 %
FEDERAL INCOME TAX RATE 50.00 %
ADVALOREM AND STATE TAX RATE 6.13 %

TABLE 26

COST OF NEW OIL
RESERVES ADDED IN 1974
TOTAL UNITED STATES

TIME YEARS	(1) GROSS OIL PRODUCTION THOUSANDS OF BBLS	(2) GROSS GAS PRODUCTION MILLIONS OF CU-FT	(3) GROSS OIL & GAS SALES THOUSANDS OF $	(4) ROYALTY EXPENSE THOUSANDS OF $	(5) ADVALOREM & STATE TAXES THOUSANDS OF $	(6) OPERATING EXPENSES THOUSANDS OF $	(7) ADJUSTED GROSS INCOME THOUSANDS OF $	(8) TOTAL INVESTED CAPITAL THOUSANDS OF $
1974	40962	57429	551667	68958	29590	39042	414076	4491000
1975	81924	114857	1103334	137917	59180	78084	828153	0
1976	81924	114858	1103333	137917	59180	78084	828153	0
1977	81924	114857	1103334	137917	59180	78084	828153	0
1978	81924	114856	1103334	137916	59180	78084	828153	0
1979	81924	114857	1103333	137917	59180	78084	828153	141000
1980	81924	114857	1103334	137917	59180	78084	828153	0
1981	80720	113169	1087115	135889	58311	78084	814831	0
1982	72706	101935	979191	122399	52521	78084	726187	0
1983	64467	90410	868495	108562	46584	78084	635266	0
1984	57197	80190	770314	96289	41318	78084	554623	0
1985	50731	71125	683232	85404	36646	78084	483097	0
1986	44995	63084	605994	75749	32504	78084	419656	0
1987	39910	55953	537487	67186	28830	78084	363388	0
1988	35397	49627	476725	59591	25570	78084	313481	0
1989	31398	44017	422833	52854	22680	76084	269215	0
1990	27847	39041	375032	46879	20116	78084	229953	0
1991	24698	34628	332636	41579	17841	78084	195131	0
1992	21907	30712	295032	36879	15825	78084	164244	0
1993	19430	27241	261679	32710	14036	78084	136849	0
SUB-TOTAL	1103927	1547705	14867433	1858429	797452	1522636	10688914	4632000
REMAINING 7.58 YRS	91073	127685	1226555	153320	65789	592222	415224	0
TOTAL	1195000	1675390	16093988	2011749	863241	2114860	11104138	4632000

TIME YEARS	(9) INTANGIBLE DRILLING COSTS THOUSANDS OF $	(10) DEPLETION ALLOWANCE THOUSANDS OF $	(11) DEPRE-CIATION THOUSANDS OF $	(12) TAXABLE INCOME THOUSANDS OF $	(13) INVEST-MENT TAX CREDITS THOUSANDS OF $	(14) FEDERAL INCOME TAXES THOUSANDS OF $	(15) AFTER TAX NET INCOME THOUSANDS OF $	(16) NET CASH FLOW THOUSANDS OF $	(17) NET CASH FLOW DISC. 15% THOUSANDS OF $
1974	2634975	31056	32565	-2284518	25	-1142284	1556361	-2934638	-2736564
1975	0	199372	65129	563650	66477	215348	612804	612803	496906
1976	0	199372	65130	563652	0	281826	546327	546327	385219
1977	0	199372	65130	563651	0	281826	546328	546328	334974
1978	0	199372	65129	563651	0	281825	546327	546327	291281
1979	103635	199372	66834	456312	2615	225541	602613	461613	214013
1980	0	199372	68834	559947	0	279973	548179	548179	220997
1981	0	196442	67822	550568	0	275284	539547	539547	189146
1982	0	176939	61069	488158	0	244079	482108	482108	146964
1983	0	156937	54163	424145	0	212073	423193	423193	112178
1984	0	139196	46058	367370	0	183685	370938	370938	85502
1985	0	123460	42625	317012	0	156506	324591	324591	65059
1986	0	109503	37806	272348	0	136173	283483	283483	49409
1987	0	97123	33533	232731	0	116366	247022	247022	37438
1988	0	86145	29741	197595	0	98798	214683	214683	28293
1989	0	76405	26380	166430	0	83215	186000	186000	21316
1990	0	67769	23397	138788	0	69394	160559	160559	16000
1991	0	60107	20752	114271	0	57135	137995	137995	11958
1992	0	53312	18406	92526	0	46263	117982	117982	8890
1993	0	47285	16326	73238	0	36619	100230	100230	6567
SUB-TOTAL	2738610	2617911	910869	4421525	69118	2141645	8547269	3915270	-14454
REMAINING 7.58 YRS	0	160375	78521	178328	0	89164	326060	326060	14454
TOTAL	2738610	2778286	987390	4599853	69118	2230809	8873329	4241330	0

GROSS OIL PRICE	$ 12.84 / BBL	ROYALTY INTEREST	12.50 %
GROSS GAS PRICE	$ .449 / THOUSAND CU-FT	FEDERAL INCOME TAX RATE	50.00 %
TOTAL RESERVE LIFE	27.58 YEARS	ADVALOREM AND STATE TAX RATE	6.13 %
LEASEHOLD INVESTMENT (000)	$ 906000.		

FIGURES

LIST OF FIGURES

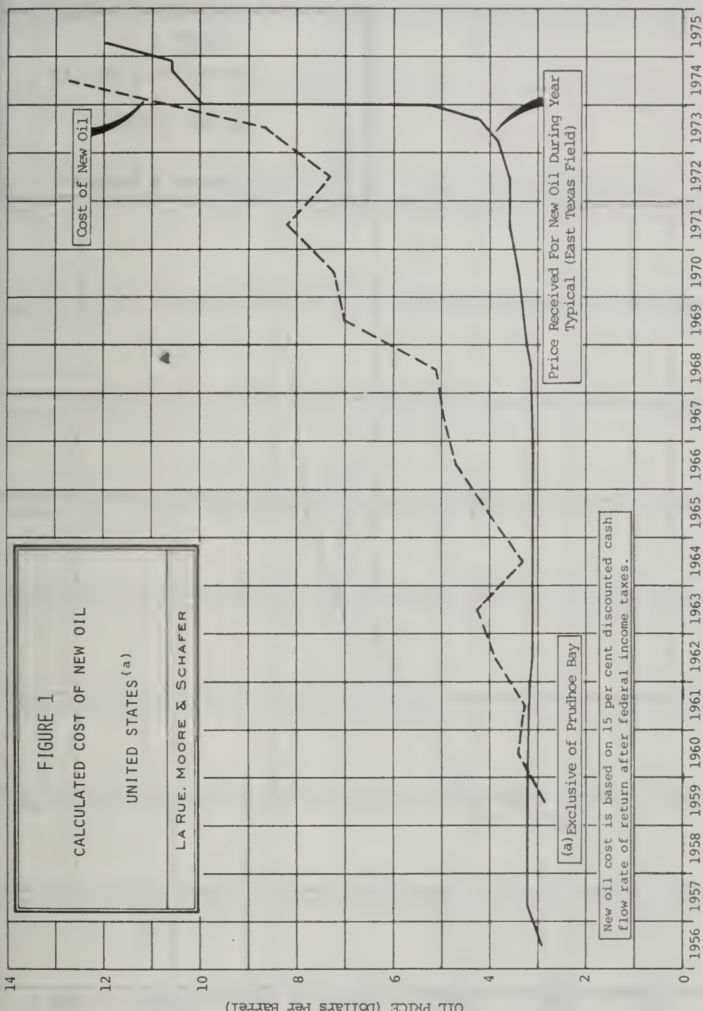

FIGURE 1

CALCULATED COST OF NEW OIL

UNITED STATES[a]

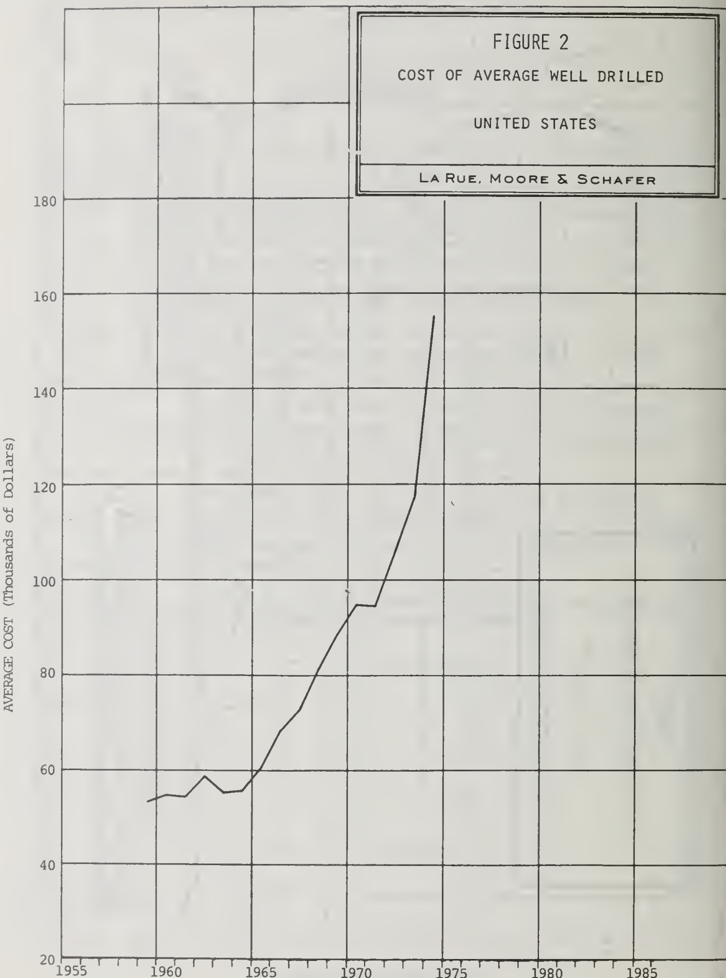
FIGURE 2
COST OF AVERAGE WELL DRILLED
UNITED STATES
LA RUE, MOORE & SCHAFER
AVERAGE COST (Thousands of Dollars)
180
160
140
120
100
80
60
40
20
1955
1960
1965
1970
1975
1980
1985

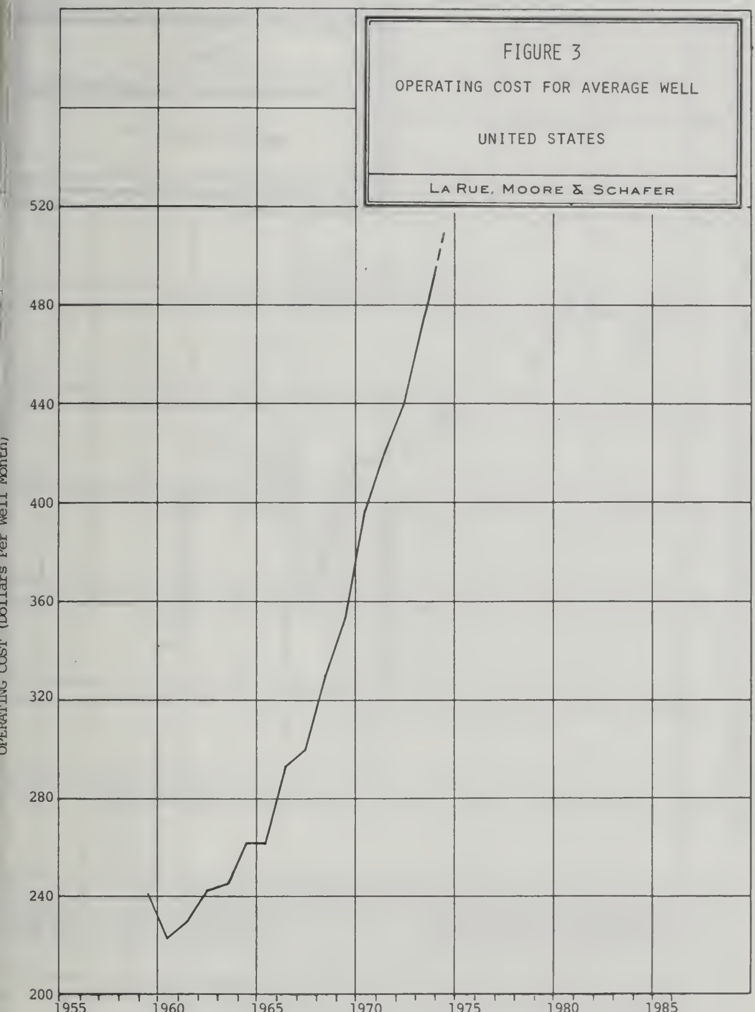

FIGURE 3

OPERATING COST FOR AVERAGE WELL

UNITED STATES

LA RUE, MOORE & SCHAFER

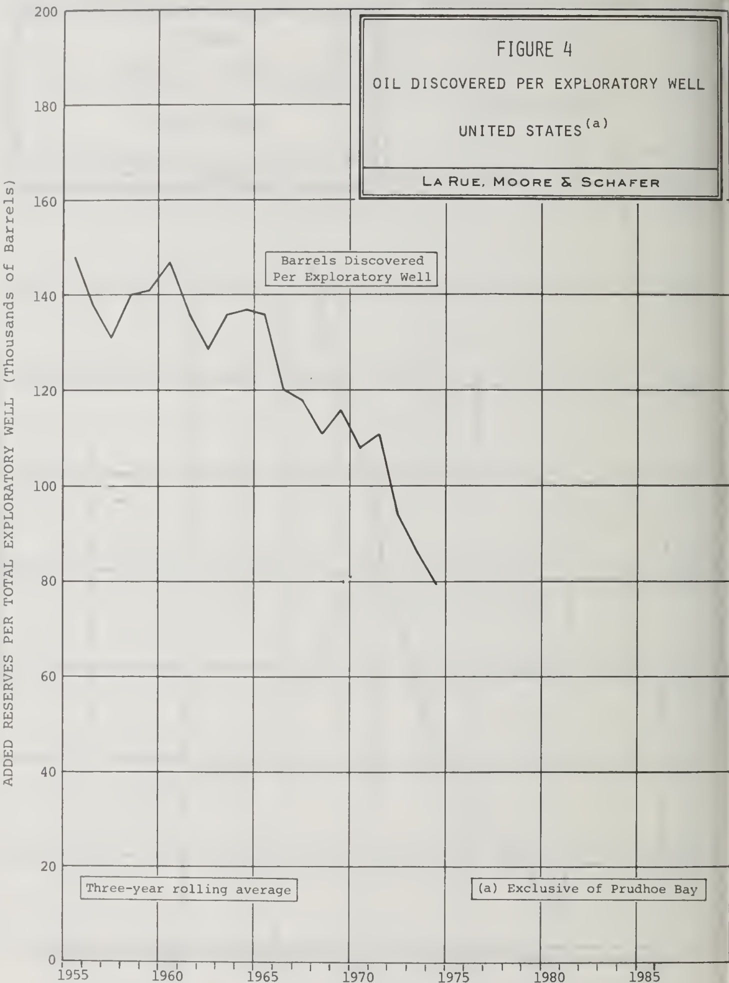
FIGURE 4
OIL DISCOVERED PER EXPLORATORY WELL
UNITED STATES(a)
LA RUE, MOORE & SCHAFER
Barrels Discovered Per Exploratory Well
ADDED RESERVES PER TOTAL EXPLORATORY WELL (Thousands of Barrels)
Three-year rolling average
(a) Exclusive of Prudhoe Bay
0
20
40
60
80
100
120
140
160
180
200
1955
1960
1965
1970
1975
1980
1985

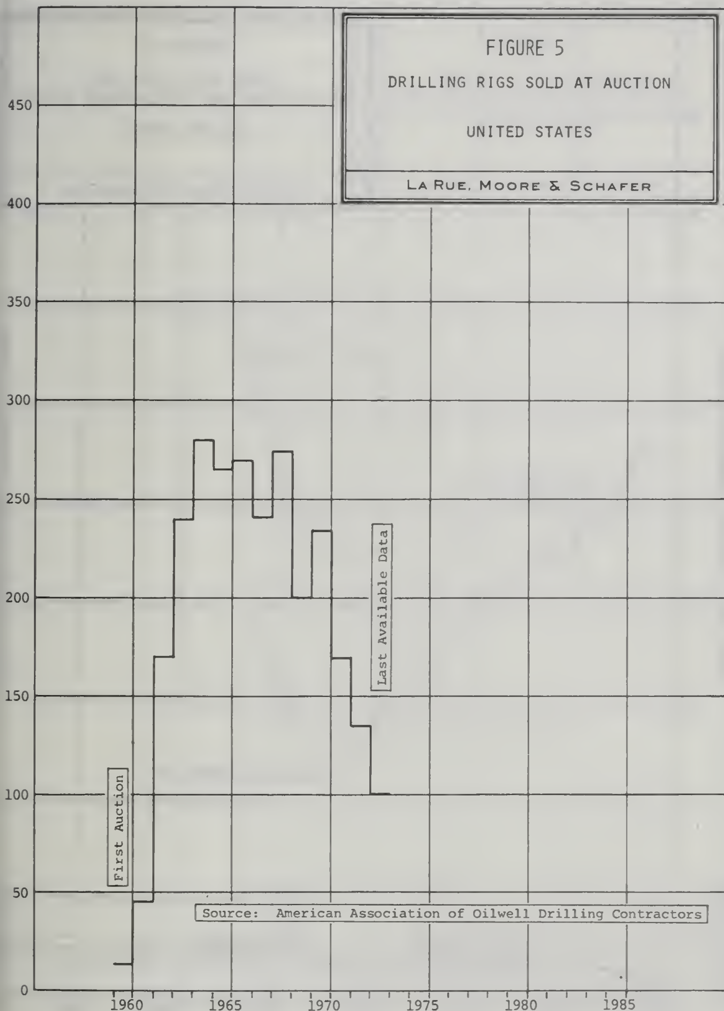
FIGURE 5
DRILLING RIGS SOLD AT AUCTION
UNITED STATES
LA RUE, MOORE & SCHAFER
First Auction
Last Available Data
Source: American Association of Oilwell Drilling Contractors
0
50
100
150
200
250
300
350
400
450
1960
1965
1970
1975
1980
1985

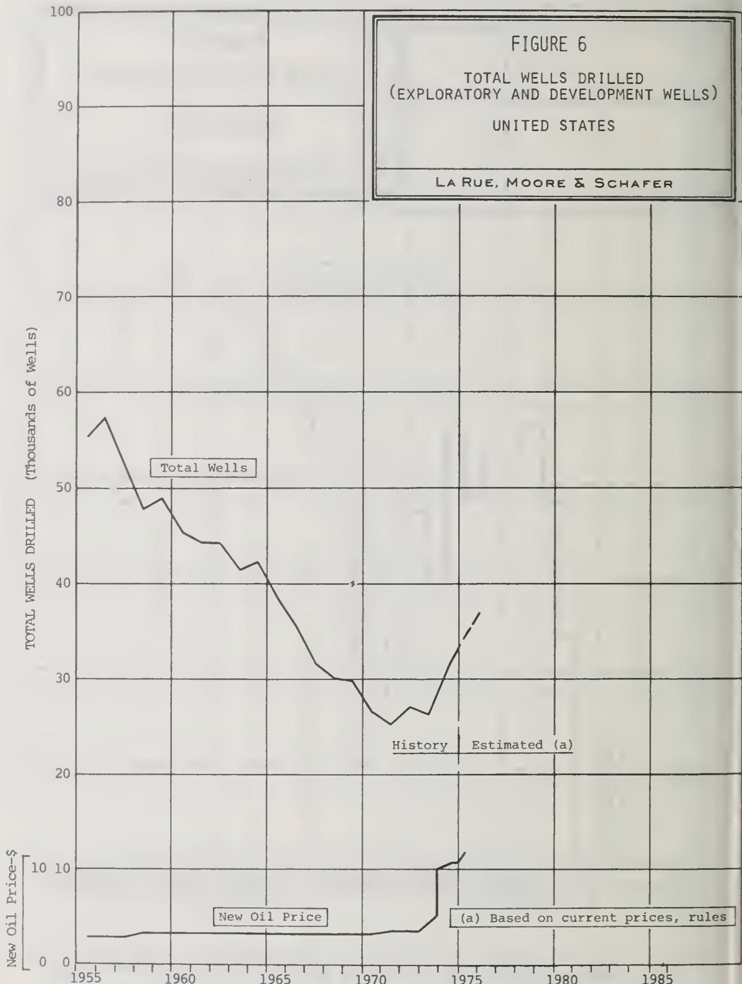
FIGURE 6
TOTAL WELLS DRILLED
(EXPLORATORY AND DEVELOPMENT WELLS)
UNITED STATES
LA RUE, MOORE & SCHAFER
TOTAL WELLS DRILLED (Thousands of Wells)
Total Wells
History
Estimated (a)
New Oil Price-$
New Oil Price
(a) Based on current prices, rules
100
90
80
70
60
50
40
30
20
10
0
1955
1960
1965
1970
1975
1980
1985

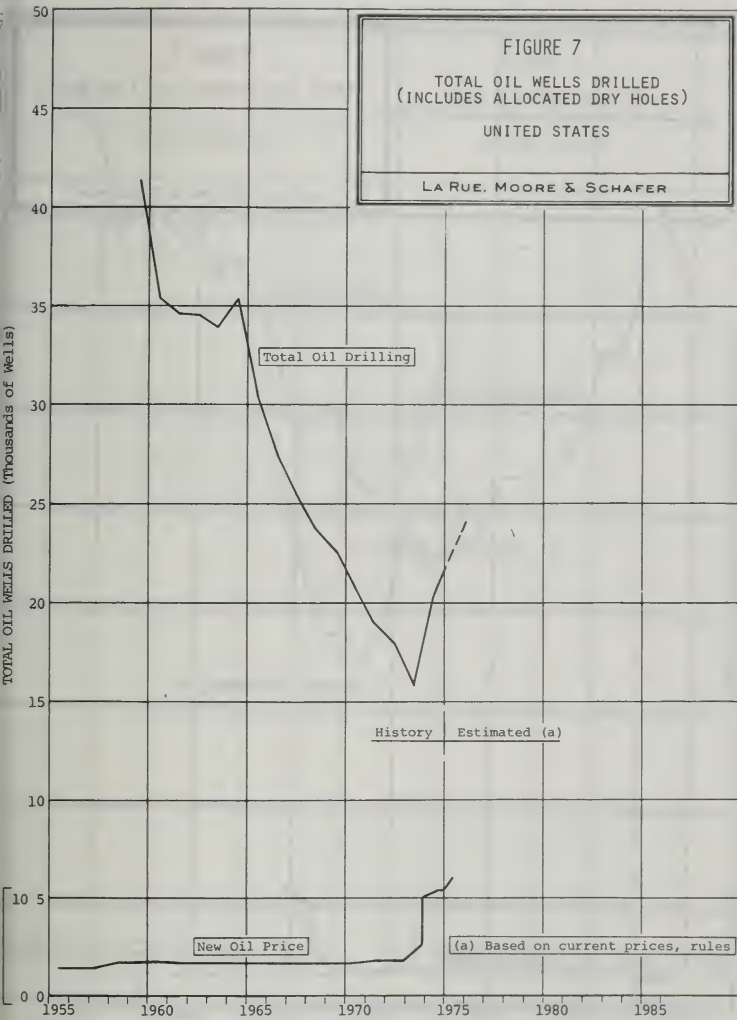
FIGURE 7
TOTAL OIL WELLS DRILLED
(INCLUDES ALLOCATED DRY HOLES)
UNITED STATES
LA RUE, MOORE & SCHAFER
TOTAL OIL WELLS DRILLED (Thousands of Wells)
Total Oil Drilling
History
Estimated (a)
New Oil Price
(a) Based on current prices, rules
50
45
40
35
30
25
20
15
10
10 5
0 0
1955
1960
1965
1970
1975
1980
1985

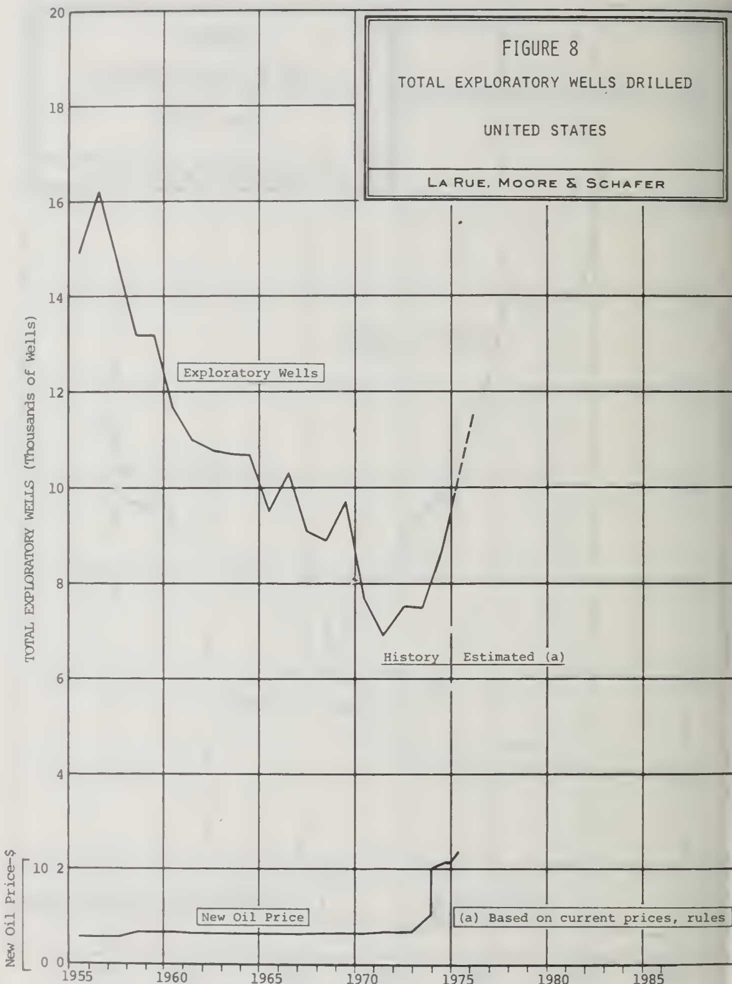
FIGURE 8
TOTAL EXPLORATORY WELLS DRILLED
UNITED STATES
LA RUE, MOORE & SCHAFER
TOTAL EXPLORATORY WELLS (Thousands of Wells)
Exploratory Wells
History
Estimated (a)
New Oil Price–$
New Oil Price
(a) Based on current prices, rules
20
18
16
14
12
10
8
6
4
2
0
10
0
1955
1960
1965
1970
1975
1980
1985

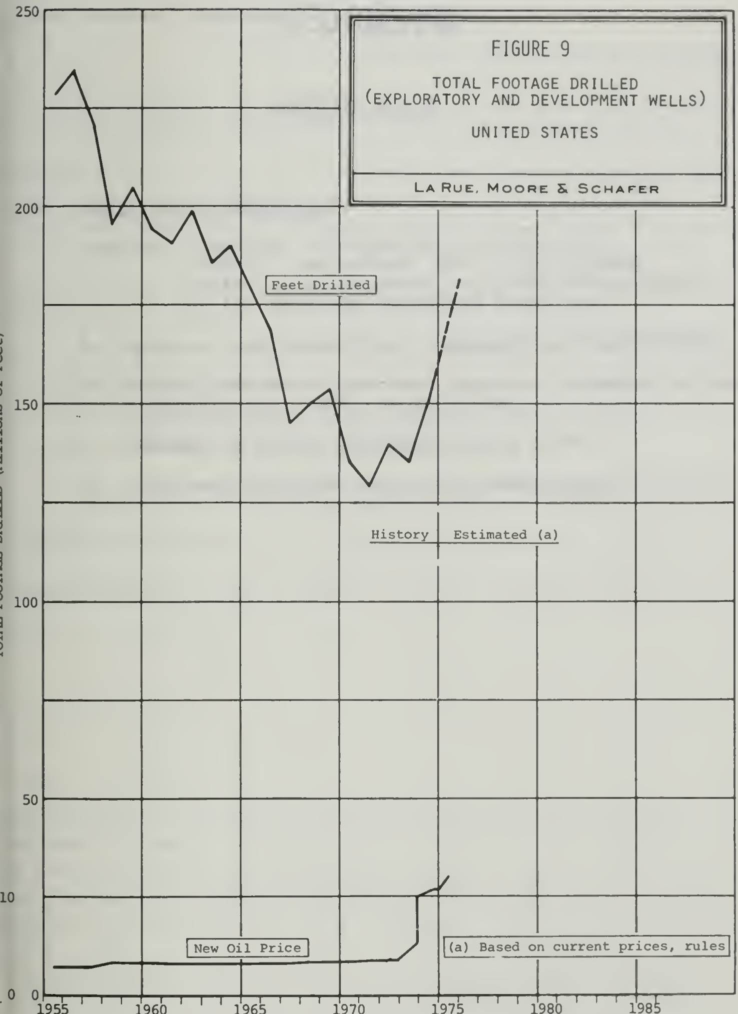
FIGURE 9
TOTAL FOOTAGE DRILLED
(EXPLORATORY AND DEVELOPMENT WELLS)
UNITED STATES
LA RUE, MOORE & SCHAFER
Feet Drilled
History
Estimated (a)
New Oil Price
(a) Based on current prices, rules
250
200
150
100
50
10
0
0
1955
1960
1965
1970
1975
1980
1985

APPENDICES

APPENDIX A - I

I. Oil Reserve Statistics.

Source: "Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States as of December 31, 1973", Published by the American Petroleum Institute.

A. Reserves and Production - Concepts and Definitions.

B. Annual Estimates of Proved Crude Oil Reserves in the United States, 1946 through 1973.

C. Changes in Proved Reserves During 1974.

D. Reserves Committee Policy and Membership, Year 1973.

APPENDIX A - I (cont'd)

RESERVES AND PRODUCTION -- CONCEPTS AND DEFINITIONS

CRUDE OIL. Crude oil is technically defined as a mixture of hydrocarbons that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. For statistical purposes, volumes reported as crude oil include:

1. Liquids technically defined as crude oil;

2. Small amounts of hydrocarbons that exist in the gaseous phase in natural underground reservoirs but are liquid at atmospheric pressure after being recovered from oil well (casinghead) gas in lease separators;* and

3. Small amounts of nonhydrocarbons produced with the oil.

Statistical data pertaining to crude oil production, reserves, and productive capacity are reported as liquid equivalents at the surface (excluding basic sediment and water) measured in terms of stock tank barrels of 42 U.S. gallons at atmospheric pressure, and corrected to $60^{\circ}F$.

*From a technical standpoint, these liquids are termed "condensate"; however, they are commingled with the crude stream and it is not practical to measure and report their volume separately. All other liquids recovered from natural gas (including lease condensate) are included in the natural gas liquid volumes reported by the AGA although some of the lease condensate which is recovered and measured separately from crude oil may be commingled with crude oil in pipelines when marketed.

Where a state regulatory agency specifies a definition of crude oil which differs from that set forth above, the Committee, for statistical purposes, follows the state definition.

In the absence of a definition by a regulatory authority, reserves, production and productive capacity data are reported on the basis of classification made by the operator.

APPENDIX A - I (cont'd)

PROVED RESERVES OF CRUDE OIL. Proved reserves of crude oil as of December 31 of any given year are the estimated quantities of all liquids statistically defined as crude oil, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation tests. The area of an oil reservoir considered proved includes: (1) that portion delineated by drilling and defined by gas-oil or oil-water contacts, if any; and (2) the immediately adjoining portions not yet drilled but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

Reserves of crude oil which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of proved crude oil reserves do not include the following: (1) oil that may become available from known reservoirs but is reported separately as "indicated additional reserves"; (2) natural gas liquids (including condensate); (3) oil the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (4) oil that may occur in untested prospects; and (5) oil that may be recovered from oil shales, coal, gilsonite and other such sources.

INDICATED ADDITIONAL RESERVES. With the present state of industry technology, certain quantities of crude oil (other than those defined and reported as proved reserves) may be economically recoverable from the following potential sources:

> Known productive reservoirs in existing fields expected to respond to improved recovery techniques such as fluid injection where (a) an improved recovery technique has been installed but its effect cannot yet be fully evaluated; or (b) an improved technique has not been installed but knowledge of reservoir characteristics and the results of a known technique installed in a similar situation are available for use in the estimating procedure.

APPENDIX A - I (cont'd)

Crude oil potentially available from these sources is reported as "indicated additional reserves." The economic recoverability of these reserves is not considered to be established with sufficient conclusiveness to allow them to be included in proved reserves; however, if and when improved recovery techniques are successfully applied to known reservoirs, the corresponding indicated additional reserves will be reclassified and added to the inventory of proved reserves. The "indicated additional reserves" are reported separately from "proved" reserves to provide continuity to the proved reserves' statistical series.

Indicated additional reserves do not include reserves associated with acreage that may be added to the area of a proved reservoir as the result of future drilling.

DISCOVERIES. Discoveries reported as of December 31 for any given year are proved reserves credited to new fields and new reservoirs in old fields as the result of successful exploratory drilling and associated development drilling during the current year.

The reliability of estimates of the proved productive area of new discoveries or partially developed reservoirs varies in relation to the amount of geological information available at the time the estimate is prepared. Important factors such as the areal extent of the structure, the average thickness of the producing reservoir, the oil column within the reservoir, and the continuity and characteristics of the reservoir formation cannot be determined accurately unless sufficient subsurface information is available.

The ultimate size of newly discovered reservoirs, whether in new fields or old fields, is seldom determined in the year of discovery. Therefore, first-year estimates of proved reserves in new reservoirs are often only a small part of the total that will be ultimately assigned to the new reservoirs. It follows that reserves credited to discoveries in any given year are usually less than total extensions and revisions for the same year, since extensions and revisions represent adjustments of reserves in reservoirs discovered in all prior years.

Subcommittees are not necessarily aware of and may not have access to the subsurface information for all new discoveries at the time reserve estimates are prepared. This is especially true if a discovery is made late in the year for which a report is being prepared or when competitive situations dictate that the subsurface information be held as proprietary. In such cases, new proved reserves are reported in Table I as discoveries in new fields or new reservoirs in old fields for the year in which the discovery becomes known or when subsurface informa-

APPENDIX A - I (cont'd)

tion becomes available. In Table III, these reserves are assigned to the year in which the field was actually discovered.

EXTENSIONS. The ultimate size of newly discovered fields, or newly discovered reservoirs in old fields, is normally determined by drilling in years subsequent to discovery. Wells drilled in subsequent years usually add to the proved area of previously discovered reservoirs, thereby serving to increase estimates of proved reserves. The reserves credited to a reservoir because of enlargement of its proved area are classified as "extensions."

REVISIONS. Both development drilling and production history add to the basic geological and engineering knowledge of a petroleum reservoir and provide the basis for more accurate estimates of proved reserves in years following discovery. Changes in earlier estimates, either upward or downward, resulting from new information (except for an increase in proved acreage) are classified as "revisions." Revisions for a given year also include (1) increases in proved reserves associated with the installation of improved recovery techniques; and (2) an amount which corrects the effect on proved reserves of the difference between estimated production for the previous year and actual production for that year.

PROVED ACREAGE. Proved acreage is that which has been credited with proved reserves. Acreage is credited with proved reserves if the presence of a productive formation has been verified by drilling and testing. Undrilled acreage adjacent to drilled acreage and certain other undrilled acreage are also credited with proved reserves if geological and engineering information demonstrate with reasonable certainty that the underlying formations are continuous and productive.

IMPROVED RECOVERY TECHNIQUES. Improved recovery techniques include all methods for supplementing natural reservoir forces and energy, or otherwise increasing ultimate recovery from a reservoir. Such techniques include: (1) pressure maintenance, (2) cycling; and (3) secondary recovery in its original sense; (i.e., fluid injection applied relatively late in the productive history of a reservoir for the purpose of stimulating production after recovery by primary methods of flowing or artificial lift has approached an economic limit). Improved recovery techniques also include thermal methods and the use of miscible displacement fluids.

Reserves resulting from the application of any of the methods listed above are

APPENDIX A - I (cont'd)

TABLE II

ANNUAL ESTIMATES OF PROVED CRUDE OIL RESERVES IN THE UNITED STATES 1946 THROUGH 1973
(Thousands of Barrels of 42 U. S. Gallons)

Year (1)	Proved Reserves at Beginning of Year (2)	Revisions (3)	Extensions (4)	New Field Discoveries (5)	New Reservoir Discoveries in Old Fields (6)	Total of Discoveries, Revisions, and Extensions (7)	Production /a (8)	Proved Reserves at End of Year (9)	Net Change From Previous Year (10)
1946	19,941,846	1,254,705	1,158,923	/b	244,434	2,658,062	1,726,348	20,873,560	931,714
1947	20,873,560	749,278	1,269,862	/b	445,430	2,464,570	1,850,445	21,487,685	614,125
1948	21,487,685	1,958,853	1,439,873	269,438	127,043	3,795,207	2,002,448	23,280,444	1,792,759
1949	23,280,444	603,566	1,693,862	544,319	346,098	3,187,845	1,818,800	24,649,489	1,369,045
1950	24,649,489	663,378	1,334,391	407,739	157,177	2,562,685	1,943,776	25,268,398	618,909
1951	25,268,398	1,776,110	2,248,588	205,959	183,297	4,413,954	2,214,321	27,468,031	2,199,633
1952	27,468,031	743,729	1,509,131	280,066	216,362	2,749,288	2,256,765	27,960,554	492,523
1953	27,960,554	1,264,832	1,439,618	344,053	247,627	3,296,130	2,311,856	28,944,828	984,274
1954	28,944,828	537,788	1,749,443	307,625	278,181	2,873,037	2,257,119	29,560,746	615,918
1955	29,560,746	696,114	1,697,653	219,824	257,133	2,870,72[illegible]	2,419,300	30,012,170	451,424
1956	30,012,170	804,803	1,702,311	234,727	232,495	2,974,336	2,551,857	30,434,649	422,479
1957	30,434,649	465,421	1,543,182	207,437	208,760	2,424,800	2,559,044	30,300,405	(134,244)
1958	30,300,405	954,605	1,338,908	151,210	163,519	2,608,242	2,372,730	30,535,917	235,512
1959	30,535,917	1,518,678	1,778,705	165,695	203,667	3,666,745	2,483,315	31,719,347	1,183,430
1960	31,719,347	787,934	1,323,538	141,296	112,560	2,365,328	2,471,464	31,613,211	(106,136)
1961	31,613,211	1,087,092	1,209,101	107,423	253,951	2,657,567	2,512,273	31,758,505	145,294
1962	31,758,505	759,053	1,041,257	92,488	288,098	2,180,896	2,550,178	31,389,223	(369,282)
1963	31,389,223	966,051	858,168	96,732	253,159	2,174,110	2,593,343	30,969,990	(419,233)
1964	30,969,990	899,292	1,419,182	126,682	219,611	2,664,767	2,644,247	30,990,510	20,520
1965	30,990,510	1,783,231	792,901	237,335	234,612	3,048,079	2,686,198	31,352,391	361,881
1966	31,352,391	1,839,307	814,249	160,384	150,038	2,963,978	2,864,242	31,452,127	99,736
1967	31,452,127	1,900,969	716,467	125,105	219,581	2,962,122	3,037,579	31,376,670	(75,457)
1968	31,376,670	1,320,109	776,780	166,291	191,455	2,454,635	3,124,188	30,707,117	(669,553)
1969	30,707,117	1,258,142	614,710	96,435	150,749	2,120,036	3,195,291	29,631,862	(1,075,255)
1970	29,631,862	2,088,927	631,354	9,852,512	116,125	12,688,918	3,319,445	39,001,335	9,369,473
1971	39,001,335	1,600,426	560,596	91,469	65,241	2,317,732	3,256,110	38,062,957	(938,378)
1972	38,062,957	820,107	459,311	123,210	155,220	1,557,848	3,281,397	36,339,408	(1,723,549)
1973	36,339,408	1,551,777	390,141	116,097	87,816	2,145,831	3,185,400	35,299,839	(1,039,569)

/a Production is the amount originally estimated and used by the committee in prior volumes of the reserves report. These figures differ from production data developed by the committee and reported in Tables III and IV.

/b All discoveries were classified as "New Reservoirs".

( ) Denotes negative volume.

APPENDIX A - I (cont'd)

ESTIMATED RESERVES OF CRUDE OIL IN THE UNITED STATES
(Thousands of barrels of 42 U.S. Gallons)

TABLE I

State (1)	Proved Reserves as of 12/31/73 (2)	Changes in Proved Reserves During 1974: Revisions Plus (3a)	Revisions Minus (3b)	Extensions (4)	New Fields Discoveries (5)	New Reservoir Discoveries in Old Fields (6)	Production /a (7)	Proved Reserves as of 12/31/74 (8)	Net Changes in Proved Reserves During 1974 (9)	Indicated Additional Reserves From Known Reservoirs /b (10)	State (11)
Alabama	53,603	25,066	602	114	1,550	–	11,013	68,718	15,115	4,000	Alabama
Alaska	10,112,213	52,495	–	–	–	–	70,609	10,094,099	(18,114)	13,000	Alaska
Arkansas	105,552	16,840	2,917	1,262	1,123	319	15,843	106,336	784	21,444	Arkansas
California /c	3,488,100	288,677	36,690	40,988	98,010	460	322,509	3,557,036	68,936	1,348,550	California /c
Coastal Region	536,284	75,487	9,789	5,055	94,010	10	73,836	627,221	90,937	164,750	Coastal Region
Los Angeles Basin	1,197,868	52,795	12,475	653	–	–	125,581	1,113,260	(84,608)	357,500	Los Angeles Basin
Sao Joaquin Basin	1,753,948	160,395	14,426	35,280	4,000	450	123,092	1,816,555	62,607	826,300	San Joaquin Basin
Colorado	304,790	13,788	3,428	7,734	2,998	362	36,911	289,333	(15,457)	97,090	Colorado
Florida	183,859	152,904	147	1,305	874	–	36,086	302,709	118,850	20,936	Florida
Illinois	152,343	37,999	4,759	840	41	4	26,679	159,789	7,446	5,900	Illinois
Indiana	26,622	1,295	280	520	73	930	4,809	24,351	(2,271)	2,200	Indiana
Kansas	401,089	49,392	11,530	14,753	1,585	1,240	61,422	395,107	(5,982)	1,500	Kansas
Kentucky	39,980	5,035	1,023	190	300	50	7,960	36,572	(3,408)	2,700	Kentucky
Louisiana /c	4,576,826	290,435	221,359	86,308	74,731	58,758	639,185	4,226,514	(350,312)	224,501	Louisiana /c
North	252,388	57,244	3,854	3,051	398	108	35,387	273,948	21,560	31,645	North
South	4,324,438	233,191	217,505	83,257	74,333	58,650	603,798	3,952,566	(371,872)	192,856	South
Michigan	72,444	11,469	–	–	16,340	–	17,954	82,299	9,855	7,500	Michigan
Mississippi	291,049	46,079	32,489	3,857	1,862	1,762	50,712	261,408	(29,641)	27,252	Mississippi
Montana	219,343	22,598	6,283	4,922	1,566	–	34,757	207,389	(11,954)	46,200	Montana
Nebraska	28,166	5,825	1,133	60	401	–	6,540	26,779	(1,387)	4,120	Nebraska
New Mexico	642,994	62,396	2,959	14,522	525	983	93,493	624,968	(18,026)	311,549	New Mexico
Northwest	23,860	4,228	485	5,120	130	–	5,646	27,207	3,347	4,050	Northwest
Southeast	619,134	58,168	2,474	9,402	395	983	87,847	597,761	(21,373)	307,499	Southeast
New York	8,288	2,500	–	1,000	–	–	890	10,898	2,610	6,400	New York
North Dakota	179,520	15,481	6,001	2,318	975	165	19,664	172,794	(6,726)	12,720	North Dakota
Ohio	124,911	–	–	7,928	120	–	9,088	123,871	(1,040)	–	Ohio
Oklahoma	1,270,964	144,062	48,230	28,630	2,345	205	165,599	1,232,377	(38,587)	204,900	Oklahoma
Pennsylvania	39,613	12,200	–	2,000	–	–	3,399	50,414	10,801	54,670	Pennsylvania
Texas /c	11,756,613	569,716	217,555	85,382	12,198	21,553	1,226,401	11,001,506	(755,107)	2,032,579	Texas /c
District 1	144,149	14,106	10,105	2,695	621	195	18,272	133,389	(10,760)	38,339	District 1
District 2	677,125	46,551	35,991	994	74	2,906	68,773	622,886	(54,239)	5,720	District 2
District 3	1,489,428	42,784	25,745	11,985	209	3,958	170,516	1,352,103	(137,325)	27,328	District 3
District 4	304,422	19,806	57,581	4,880	902	7,306	42,543	237,192	(67,230)	38,550	District 4
District 5	126,462	3,807	817	282	995	140	19,977	110,892	(15,570)	36,000	District 5
District 6	2,049,248	23,156	6,560	1,431	750	254	154,621	1,913,658	(135,590)	199,351	District 6
District 7-B	235,870	51,361	13,691	10,799	945	749	35,646	250,387	14,517	10,700	District 7-B
District 7 C	204,996	19,197	13,595	17,533	708	265	29,517	199,587	(5,409)	9,028	District 7-C
District 8	3,205,538	115,922	18,277	20,279	3,996	2,951	265,893	3,064,516	(141,022)	978,247	District 8
District 8-A	2,785,308	153,420	9,969	6,212	758	1,477	359,003	2,578,203	(207,105)	678,261	District 8-A
District 9	363,708	61,362	20,296	4,184	1,975	990	42,101	369,822	6,114	7,555	District 9
District 10	170,359	18,244	4,928	4,108	265	362	19,539	168,871	(1,488)	3,500	District 10
Utah	264,512	15,075	23,028	32,000	1,300	–	39,211	250,648	(13,864)	40,500	Utah
West Virginia	32,126	–	–	1,998	720	15	2,649	32,210	84	5,000	West Virginia
Wyoming	916,763	105,823	17,083	28,757	6,250	757	137,907	903,360	(13,403)	140,007	Wyoming
Miscellaneous /d	7,556	1,414	139	1,530	276	–	2,166	8,471	915	500	Miscellaneous /d
Total U.S.	35,299,839	1,948,564	637,635	368,918	226,163	87,563	3,043,456	34,249,956	(1,049,883)	4,635,718	Total U.S.
Gulf of Mexico /e	2,347,525	139,027	61,948	34,664	73,528	37,225	358,013	2,212,008	(135,517)	50,215	Gulf of Mexico /e

/a Preliminary estimate.

/b Additional reserves include additional recoveries in known reservoirs (in excess of the proved reserves) which engineering knowledge and judgment indicate will be economically available by application of fluid injection, whether or not such program is currently installed.

/c Includes offshore reserves.

/d Includes Arizona, Missouri, Nevada, South Dakota, Tennessee, and Virginia.

/e Included with Texas and Louisiana.

( ) Denotes negative volume.

I. (i)

APPENDIX A - I (cont'd)

COMMITTEE ORGANIZATION AND POLICIES

Each member of the committee (except the Secretary) appoints one or more subcommittees for the purpose of preparing reserves and productive capacity estimates for his area of responsibility. These Subcommittees, which are responsible for determining annual reserves and productive capacity estimates, are composed of geologists and engineers who (1) represent various segments of the producing industry having prominent ownership holdings in the Subcommittee's assigned area; (2) have broad experience in the estimation of reserves and productive capacity; and (3) have an intimate knowledge of the areas and the more significant sized fields assigned to them. The Subcommittees are expected to make multiple assignments of selected fields to their members where it will beneficially contribute to the quality of reserve and productive capacity estimates and promote the exchange of expert views important thereto.

Members of the API Committee on Reserves and Productive Capacity, subcommittee chairmen, and members of the subcommittees are listed on pages 8 and 9. Areas of responsibilities, and subdivisions of California, Louisiana, New Mexico, and Texas used in reporting reserves data are shown on Maps I - V.

The Committee on Reserves and Productive Capacity operates under the API policy on petroleum statistics which includes the following:

> "Statistical information is published under Institute sponsorship in the maximum degree of detail consistent with the safeguarding of proprietary information of individual companies, while mindful of the cost and utility of the data involved. The Institute's statistics are confined to current and historical data. The Institute does not participate in the publication of forecasts of future demand for petroleum or its products, nor of estimates of crude oil, natural gas, or natural gas liquids recoveries that are speculative in nature or that rely upon conjecture regarding future physical or economic conditions."

APPENDIX A - I (cont'd)

To assure continued cooperation of its subcommittee members who exercise complete integrity and a high degree of professional judgment in the performance of their assignments, the committee adheres to the firm policy of maintaining strict confidence with respect to basic data and estimates of reserves and productive capacity for individual fields. No member of the committee or its subcommittees is authorized to make available to anyone outside the committee organization any information beyond that which is published in this report.

APPENDIX A - I (cont'd)

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APPENDIX A - I (cont'd)

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APPENDIX A - II

II. Industrywide Cost Statistics.

Source: Joint Association Survey of the U. S. Oil and Gas Producing Industry, Published by the American Petroleum Institute.

A. Summary of Findings, Section I. Drilling Costs, Year 1973, Instructions and Definitions for JAS Section I.

B. Estimated Expenditures for Exploration, Development and Production of Oil and Gas in the United States. Instructions and Definitions for JAS Section II.

APPENDIX A - II (cont'd)

JOINT ASSOCIATION SURVEY – 1973
SECTION I: DRILLING COSTS

SUMMARY OF FINDINGS. Findings pertaining to 1973 drilling costs and activity in the United States may be summarized as follows:

- The total cost of drilling and equipping oil and gas wells and dry holes in 1973 amounted to approximately $3,075 million, an increase of 9.3 per cent over 1972.
- The average depth of oil wells completed in 1973 was 4,602, an increase of 2.2 per cent; the average cost per foot in 1973 was $22.54, an increase of 8.5 per cent over the previous year.
- The average depth of gas wells in 1973 was 5,654 feet, a decrease of 0.4 per cent from 1972; the average cost per foot was $27.46 compared to $27.78 in 1972.
- The average depth of dry holes drilled in 1973 was 5,504 feet, an increase of 0.2 per cent; the average cost per foot was $19.22, an increase of 11.2 per cent over 1972.
- The total number of wells drilled in 1973 decreased 0.8 per cent, and the total footage increased 0.8 per cent.
- The total cost of offshore wells completed in 1973 amounted to over $578 million, a decrease of 8.6 per cent over 1972. The total number of offshore wells decreased 10.6 per cent and the average depth of offshore wells decreased 6.6 per cent. The average cost per foot was $69.23 in 1973, an increase of 9.5 per cent.
- The comparison of drilling activity and the cost of various types of wells completed in 1972 and 1973 is as follows:

	Oil Wells		Gas Wells	
	1972	1973	1972	1973
Wells Drilled	10,753	9,705	5,086	6,427
Footage Drilled (000)	48,400	44,667	28,885	36,337
Total Cost (millions)*	$1,005	$1,007	$802	$998
Average Depth (feet)	4,501	4,602	5,679	5,654
Average Cost Per Well*	$93,506	$103,758	$157,764	$155,272
Average Cost Per Foot*	$20.77	$22.54	$27.78	$27.46

	Dry Holes		Total Wells	
	1972	1973	1972	1973
Wells Drilled	10,604	10,112	26,443	26,244
Footage Drilled (000)	58,251	55,657	135,536	136,661
Total Cost (millions)*	$1,006	$1,070	$2,814	$3,075
Average Depth (feet)	5,493	5,504	5,126	5,207
Average Cost Per Well*	$94,899	$105,778	$106,424	$117,152
Average Cost Per Foot*	$17.28	$19.22	$20.76	$22.50

*Includes all costs incurred for drilling and equipping wells through the "Christmas tree."

NOTE: Totals may not agree with the sum of the individual items because of independent rounding.

APPENDIX A - II (cont'd)

APPENDIX B, P. 1

INSTRUCTIONS AND DEFINITIONS FOR JAS-SECTION I

1. If a well shown on the computer listing was completed by you as operator in the survey year (whether actually drilled by you or drilled for you by a contractor), you only need to insert the total cost of the well as defined in Section 14 below.

2. Wells shown on the computer listing not actually completed by you during the calendar survey year should be deleted from the computer list.

3. If as operator, you completed wells in the calendar survey year not shown on the computer listing, such wells should be reported on the enclosed blank forms.

4. WELLS TO BE REPORTED. Report each domestic well completed by you as operator in the survey year (whether actually drilled by you or drilled for you by contractors). Report each well completed by you *as operator* regardless of the size of your working interest in the well. Do not report wells drilled by others in which you may have had only part of a working interest regardless of the size of such interest. Do not report wells started in the survey year or in prior years, but not completed as of December 31 of the survey year. Do not report wells reentered for completion at shallower depths, old wells drilled deeper, redrilled wells, old wells worked over, stratigraphic tests, core tests, or service wells (including input wells).

5. SHORE. Enter "OFF" if well is located offshore; enter "ON" if it is onshore. An offshore well is one which is bottomed at, or produces from, a point which lies seaward of the coastline. If a state agency uses a different basis for classifying onshore and offshore wells, the state classification should be used. In general, the term "coastline" means the line of ordinary low water along that portion of the coast which is in direct contact with the open sea or the line marking the seaward limit of inland waters. For purposes of the JAS, Cook Inlet (Alaska) is classified as "offshore."

6. OP CODE. Make no entry. The API will supply the operator code.

7. WELL IDENTIFICATION NUMBER. Enter the state designated API number if it is available. Where states do not assign API Well Numbers, or if you do not know the number, leave this item blank.

8. TYPE. Insert the classification for each well reported as either an exploratory (EXPL) or a development (DEV) well. Exploratory wells include new-field wildcats, new-pool wildcats, deeper-pool tests, shallower-pool tests, and outposts (extensions). Development wells include all wells drilled to produce oil or gas from pools discovered by previous drilling. If your system of classification differs from that used by the API-AAPG, you may report wells on the basis of classification reflected in your accounts.

   Subclassify all wells as either (1) oil wells, (2) gas wells, or (3) dry holes, e.g. "EXPL-OIL," "DEV-GAS," etc. An *oil well* is one which can produce hydrocarbons existing in the reservoir in liquid form. A *gas well* is one which can produce hydrocarbons existing initially in a gaseous phase in the reservoir. So-called gas condensate wells should be reported as gas wells. The state regulatory classification should be used, if available; if not available, use a classification by company engineers.

APPENDIX A - II (cont'd)

Count *multiple completions* as one well. Report a multiple completion well as an oil well if oil is produced from at least one of several zones, even though gas and gas condensate may be produced from one or more zones in the same well. Report a multiple completion well as a gas well if oil is not produced from any of the several zones.

9. **OIL ZONES, GAS ZONES**. Enter the total number of oil zones and gas zones in the appropriate space. For a dry hole enter the word "DRY."

10. **DEPTH**. Report for each well the total feet of penetration measured down the well bore. Include all plugged back footage, but exclude bypassed footage resulting from remedial sidetrack drilling operations.

11. **COMPLETION DATE**. Enter month and year of completion.

12. **SECTION, TWP, RANGE**. Enter location data if appropriate for area.

13. **LOCATION**. Enter other available information that would be helpful in identifying well location.

14. **TOTAL COST**. Report the *total* cost (tangible and intangible) of each well completed by you as operator in the survey year (whether actually drilled by you or drilled for you by contractors). The *total* of such costs should be reported even though you as operator had only a part of a working interest in the well. Do not report the cost of wells drilled by others in which you had a working interest regardless of the size of such interest. The costs to be reported are those associated with wells which were completed during the survey year and the dollar amount to be reported is the accumulated cost of such wells from the time locations were made until the wells were completed as productive wells or abandoned after drilling was terminated because they were non-productive.

    In general, the elements contributing to reported cost are the expenditures for drilling dry holes and productive wells and equipping new productive wells through the Christmas tree installation. More specifically, these cost elements are the costs of labor, materials, supplies, water, fuels, power, and direct overhead (i.e., field, district, and regional), for such operations as site preparation, road building, erecting and dismantling derricks and drilling rigs, drilling hole, running and cementing casing, hauling materials, etc. Include the total cost of water, if purchased, or cost of water well, if drilled and chargeable to oil or gas well drilling operations. Well costs also include machinery and tool charges and rentals, and depreciation charges, where appropriate, for rigs and other equipment and facilities which will be used in drilling more than one well. Deduct the condition value of materials salvaged after use where appropriate.

    Do not report the cost of lease equipment such as artificial lift equipment and downhole lift equipment, flow lines, flow tanks, separators, etc., that are required for production. Do not reduce reported costs by test well, bottom hole, or dry hole contributions.

    For offshore wells, include costs of fixed platforms and islands. Where facilities serve more than one well, the costs should be allocated to each well on the basis of the operator's best current estimate of the ultimate number of wells that will use the facility. Also, include cost expirations (depreciation or amortization) for company-owned mobile platforms, barges, and tenders.

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TABLE I

ESTIMATED EXPENDITURES FOR EXPLORATION, DEVELOPMENT, AND PRODUCTION OF OIL AND GAS IN THE UNITED STATES, 1969-1973*

(Millions of Dollars)

	1969	1970	1971	1972	1973
1. Exploration:					
a. Drilling and Equipping Exploratory Wells	$ 944	$ 815	$ 775	$ 910	$1,021
b. Acquiring Undeveloped Acreage	1,137	714	642	1,722	3,646
c. Lease Rentals and Exp. for Carrying Leases	134	138	143	142	155
d. Geological and Geophysical	387	349	361	372	429
e. Contributions Toward Test Wells	33	30	24	35	38
f. Land Dept., Leasing, and Scouting	93	98	100	105	102
g. Other incl. Direct Overhead	168	143	142	147	181
h. G & A Overhead Allocated to Exploration	210	189	206	239	293
i. Total Exploration	3,106	2,476	2,393	3,672	5,865
2. Development:					
a. Drilling and Equipping Development Wells	1,634	1,733	1,573	1,869	2,016
b. Lease Equipment	442	443	388	497	524
c. Improved Recovery Programs	303	285	323	310	276
d. Other incl. Direct Overhead	180	170	185	160	189
e. G & A Overhead Allocated to Development	207	220	202	257	250
f. Total Development	2,766	2,851	2,671	3,093	3,255
3. Production:					
a. Production Expenditures incl. Direct Overhead	2,189	2,379	2,504	2,563	2,792
b. Production or Severance Taxes	525	563	587	613	683
c. Ad Valorem Taxes	271	294	295	269	275
d. G & A Overhead Allocated to Production	369	416	465	467	485
e. Total Production	3,354	3,652	3,851	3,912	4,235
TOTAL EXPENDITURES	$9,226	$8,979	$8,915	$10,677	$13,355

*Exclusive of federal, state, and local income taxes; payment of interest; payments for the retirement of debt; and payments to owners as a return on investment.

APPENDIX A - II (cont'd)

JOINT ASSOCIATION SURVEY–SECTION II

NOTES AND INSTRUCTIONS

GENERAL:

Section II of the Survey supplements the information in Section I. It includes not only expenditures for drilling and equipping wells, but also all other expenditures incident to finding, developing, and producing oil and gas in the United States. It should be noted, however, that all net working interest expenditures should be reported, whether for operated or non-operated properties. Expenditures should be reported only by those directly engaged in drilling and producing operations. Do not report expenditures or revenues applicable to gas processing plants or gas systems.

The revenues included in this Section include primarily the receipts (after royalty payments, production payment disbursements, and net profits disbursements) of producers from their net company interest in oil and gas production recorded in the books of account in the calendar year. Also included are certain non-operating revenues from other sources, such as from royalty interests, net profit interest receipts, production payment receipts, etc., owned in productive properties. On the other hand, receipts of royalty owners not directly engaged in drilling and production are excluded from reported revenues.

In order that the information gathered shall be on a comparable basis, each reporting company is requested to report its total net working interest expenditures as outlined below. Report only the expenditures recorded on the books of account (whether actually paid or accrued) in each category during the calendar year 1973. Report all such relevant expenditures, whether incurred for current expenses or on capital account. Include in overhead items only those resulting from cash expenditures during the year. Exclude non-cash items such as depletion, depreciation, and amortization, etc., except that in General and Administrative Overhead, Item B-4, depreciation may be charged for office buildings, etc. (where the total cash expenditure for such facilities are not reported elsewhere).

Definitions: "Casinghead gas" or "percentage" type contracts as used herein applies to an arrangement whereby the lease owner sells raw gas (measured in MCF) to a gas processing plant. The amount received by the lease owner under this type of contract is usually based on a percentage of the value of the residue gas sold plus an additional amount for the value of the additional product (including sulfur) content of the gas.

A "processing" type contract as used herein is an arrangement whereby the lease owner furnishes gas to a plant for processing, retaining title to the residue gas remaining after processing. The processing is performed for a fee or a settlement solely out of the products extracted with the lease owner receiving the remainder of the product (including sulfur) proceeds.

The following detailed instructions are numbered to correspond with the item numbers on the questionnaire form.

A. PRODUCTION AND REVENUE–UNITED STATES OIL AND GAS OPERATIONS

A-1. Crude Oil and Lease Condensate

Report the net company working interest in crude oil and lease condensate produced. The volume should be the net company working interest in liquids produced from all wells in which all or part of the working interest is owned, including unitized projects. The volume reported should not include liquid products derived from gas processed under casinghead or percentage type contracts, from cycling operations and/or under processing type contracts.

The value reported should be the amount of revenue credited to the lease (after royalty payments, production payment disbursements, and net profit disbursements). Do not include the lease sales value of liquid products derived from gas processed under a casinghead or percentage type contract, which is to be reported in Item A-2, or from cycling operations and/or under processing type contracts which is to be reported under A-2 or A-3 depending on the basis recorded in company accounts. Do not deduct production or severance taxes since these should be reported as expenditures in Item B-3-b.

A-2. Natural Gas Sales

Volume

Report the volume of net company working interest in gas produced from oil and gas wells, and subsequently sold, including

(1) The volume of gas delivered to respondent's own gas processing plants or gas systems. For cycling operations and/or under processing type contracts, if the sale of residue gas and liquid products is recorded on a separate basis, report only the leases' share of the net company working interest in residue gas sold by the plant. If recorded on a raw gas basis, as under a casinghead contract, report the net working interest raw gas volume.

(2) The volume of gas used in drilling or producing operations, if the value of such gas is credited to lease revenue with a corresponding charge to lease operations.

Exclude the following.

(1) The volume of residue gas sold (or returned for lease operations) where such residue gas (or proceeds therefrom) represents all or part of the consideration received from the sale of casinghead gas, as under a casinghead or percentage type gas contract. (The inclusion of residue gas volume would amount to duplication, since residue volume is included in the volume of raw gas sold to the gas processing plant.)

(2) The volume of gas returned to the producing reservoir.

The volumes reported should be at the pressure base reflected in the accounts of the reporting producers, and such volumes need not be adjusted to any uniform pressure base, such as 14.65 psi. However, please record the pressure base used in the space provided.

Value

The value of net company working interest in gas produced from oil and gas wells and credited to lease revenues should include:

(1) Revenue received from sale of gas. This value should include (a) the revenue derived from the sale of liquids and residue gas extracted from gas processed under casinghead or percentage type contracts, and (b) the revenue received from the sale of residue gas from cycling operations or under processing type contracts if so recorded in company accounts. If recorded on a raw gas basis, report the revenue from both residue gas and liquids.

(2) The value of gas delivered to respondent's own gas processing plants or gas systems which is credited to the lease.

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(3) The value of gas used in drilling or producing operations, including residue gas returned from plants, if the value of such gas is credited to lease revenue with a corresponding charge to operations.

A-3. Leases' Share of Liquids Recovered from Cycling Operations and/or under Processing Type Contracts

Report the leases' share of the net company working interest in the volume and value of liquids recovered from cycling operations and/or under processing type contracts, if recorded separately on company records. If not separated, report the volume and value of the leases' share of liquids sold from such operations (on a raw gas basis) under Item A-2.

A-4. Oil and Gas Royalty Revenue

Report oil and gas revenue from royalties owned plus revenue from oil payment interests received, net profit interests received, etc.

A-5. Other Lease Revenues from Producing Operations

Report any other lease revenues strictly incidental to oil and gas operations, such as equipment rentals; receipts from services performed for others, sales of water or steam, etc. Do not include revenue attributable to operations of gas processing plants or gas systems, or receipts from sale of assets, producing properties, etc. Do not include revenue applicable to mined sulfur, oil shale, uranium, or other mineral operations.

B. EXPLORATION, DEVELOPMENT, AND PRODUCTION EXPENDITURES FOR UNITED STATES OIL AND GAS OPERATIONS (Whether Capitalized or Expensed)

In this section, the classification of exploratory and development well expenditures should be based on the AAPG well classifications as used in Section I, as follows:

(1) Exploratory wells which include new-field wildcats, new-pool wildcats, deeper-pool tests, shallower-pool tests, and outposts (extensions).

(2) Development wells which are those wells drilled to produce oil or gas from pools discovered by previous drilling.

Report only expenditures for the company's net working interest, whether for company operated or non-operated properties. Report expenditures for dry holes as exploratory or development (under B-1-a or B-2-a) in accordance with the above classification. Because service wells do not fall necessarily within any one category of expenditures, see definitions below (B-2-c and B-2-d) for treatment of expenditures for service wells.

Exclude expenditures incident to mined sulfur, oil shale, uranium, or other mineral operations.

B-1-a. Expenditures for Drilling and Equipping Exploratory Wells (Including Platform Costs)

Report all expenditures (reduced by the amount of outside cash contributions such as bottom hole or dry hole) for drilling exploratory wells including successful wells completed, dry holes, and wells still drilling at end of the year. Include (a) expenditures for casing, tubing, and wellhead fittings associated with exploratory wells, (b) expenditures for roads, grading, etc.; (c) expenditures for drilling platforms, and all other expenditures incident to exploratory drilling. Reduce cost of exploratory dry holes by salvage of equipment capable of reuse. Exclude all expenditures for equipment beyond the Christmas tree and expenditures for all downhole pumping and artificial lift equipment which should be reported in B-2-b.

B-1-b. Expenditures for Acquiring Undeveloped Acreage

Report expenditures incurred during the year for acquiring undeveloped acreage including lease bonuses, advance initial rentals which because of unusual circumstances are actually in the nature of a bonus, and any other outlays necessary to acquire leases, mineral rights, and fee lands incident to oil and gas exploration. Exclude annual rentals and other lease-carrying expenditures which should be reported under Item B-1-c.

B-1-c. Lease Rentals and Other Expenditures for Carrying Leases

Report expenditures made during the year for lease rentals and other expenditures for carrying leases, such as shut-in royalties and annual payments. Omit land department, leasing, and scouting expenditures, which should be reported under Item B-1-f.

B-1-d. Geological and Geophysical Expenditures

Report all expenditures for geological and geophysical exploration. Include expenditures for capital equipment identifiable with G & G and for core drilling (such as some types of slim hole stratigraphic tests) where the intention in advance of drilling is not to complete the well as a producing well, and/or when such tests are drilled in such a manner that productive completion is not possible.

B-1-e. Contributions Toward Test Wells

Report all contributions toward test wells, including dry hole money, bottom hole money, etc. Do not include the cost of acreage contributions.

B-1-f. Land Department, Leasing, and Scouting Expenditures

Report all land department, scouting, and lease acquisition expenditures except the actual outlays for purchase or land leasing reported under Items B-1-b and B-1-c above.

B-1-g. Other Exploration Expenditures (Including Direct Overhead)

Report all expenditures not listed above, which relate to exploration for oil and gas, whether such expenditures are capitalized or expensed on the books of account. Include expenditures for exploratory capital equipment constructed or purchased, not included in B-1-a through B-1-f above. Include direct overhead, especially at district and field levels, where such overhead can be identified with the exploratory function, e.g., district supervisory salaries; ad valorem taxes on non-producing leases; and taxes on buildings and equipment used for exploratory purposes. Report exploration overhead costs which cannot be directly identified with exploratory activities undertaken during the year under Item B-4. Exclude all exploratory outlays not specifically devoted to oil and gas operations such as for mined sulfur, oil shale, uranium, or other minerals.

B-2-a. Expenditures for Drilling and Equipping Development Wells (Including Platform Costs)

Report all expenditures for drilling development wells including successful wells completed, dry holes, and wells still drilling at end of the year. Include (a) expenditures for casing, tubing, and wellhead fittings associated with development wells, (b) expenditures for roads, grading, etc.; (c) expenditures for drilling platforms, and all other expenditures incident to development drilling. Exclude all

APPENDIX A - II (cont'd)

expenditures for equipment beyond the Christmas tree and all expenditures for downhole pumping and artificial lift equipment which should be reported under B-2-b.

B-2-b. Lease Equipment Expenditures

Report all lease equipment expenditures beyond the Christmas tree installation, including flow lines, flow tanks, field separators, heater-treaters, and related field facilities. Include expenditures for all normal pumping and other artificial lift equipment, including downhole installations required for primary production.

B-2-c. Expenditures for Fluid Injection and Improved Recovery Programs

Fluid injection and improved recovery programs include gas injection, water injection, steam injection, miscible phase, in situ combustion, etc., associated with oil and gas production. Report expenditures for procuring and installing all facilities and for drilling service wells, or converting existing wells to service wells, associated with such programs. Facilities should include pumps, compressors, engines, tankage, gathering and injection lines, treating facilities, special downhole and surface equipment, etc. Service wells include wells used for gas injection, water injection, steam injection, air injection, and water supply for injection. Do not include expenditures for observation wells, salt water disposal wells, water supply wells, or other wells required for primary production operations which should be reported under Item B-2-d.

B-2-d. Other Development Expenditures (Including Direct Overhead)

Report all other development expenditures, including such items as access facilities to district installations (as opposed to individual wells) such as roads, bridges, canals, and other improvements; camp and district facilities, fuel gas systems, observation wells, salt water disposal wells, and water supply wells other than reported under B-2-c, directly assignable overhead expenditures, and expenditures for capital equipment used for development not otherwise accounted for. Exclude expenditures for equipment and buildings used by personnel engaged in general producing and administrative activities as distinguished from development operations.

Report overhead expenditures which cannot be directly identified with development activities during the year under Item B-4. Also exclude expenditures for development not specifically devoted to oil and gas operations, such as for mined sulfur, oil shale, uranium, or other minerals.

B-3-a. Production Expenditures (Including Direct Overhead)

Report lifting expenditures and all other expenditures which are directly applicable to the production of oil and gas, as distinguished from exploratory and development activities. Include expenditures for labor, supervision in the field; repair and maintenance including workovers, production platforms, fuel, power and water, small tools and supplies; cost of treating oil, teaming and trucking, insurance; taxes (not including production and ad valorem taxes, and federal and state income taxes), bailing, shooting, fracturing, and acidizing, when not part of original completion work, abandonments, and expenditures for maintaining field offices. Include direct overhead, especially at district and field levels, where such overhead can be directly identified with the production function. Do not include expenditures applicable to gas processing plants or gas systems.

B-3-b. Production or Severance Taxes

Report here the total payments for production or severance taxes to state and local governments Do not reduce the value of crude oil and natural gas produced at the wellhead by such amounts.

B-3-c. Ad Valorem Taxes

Report expenditures for ad valorem taxes on producing properties or equipment thereon, buildings, lease or field facilities, and other property used in production operations Exclude ad valorem taxes on undeveloped properties and property taxes on buildings and equipment used for exploratory purposes, which should be included in Item B-1-g, ad valorem taxes on office buildings or other facilities used for general and administrative purposes, which should be included under Item B 4 to the extent that they are applicable to the operations covered by this report

B-4. General and Administrative Overhead Not Reported Elsewhere

Report all general operating and administrative expenditures above the field level, which are applicable to exploration, development, and production activities, excluding only those items which have been directly classified under Items B-1-g B-2-d and B-3-a Include salaries and office expenditures and depreciation charges for office buildings, etc (Note Including such depreciation is in accordance with the instructions as set forth under General Notes for reporting expenditures) If engaged in activities other than the production of oil and gas include under this heading only that portion of general and administrative expenditures allocable to the oil and gas exploration and production departments. Do not include interest on investment or state and federal income taxes

General and administrative overhead reported in total under Item B-4-e may be distributed to exploration (B-4-a), development (B-4-b), and production (B-4-c), in accordance with company practice If allocations are customarily made between exploration and production functions, but not between development and production, the total of development and production may be entered under B-4-d If allocations are not customarily made, such allocations are optional.

B-6. Expenditures for Drilling and Production Platforms (Memorandum Only)

Report total expenditures during the year for drilling and production platforms, whether such platforms were located on inland waters or offshore Platform expenditures were included in Section I on the basis of allocation of pertinent expenditures among currently completed wells In Section II drilling platform expenditures should be included in expenditures for drilling and equipping exploratory and development wells under Items B-1-a and B-2-a Expenditures for production platforms should be included under Item B-3-a. However, expenditures for drilling platforms and production platforms also should be reported under Items B-6-a and B-6-b for memorandum purposes

APPENDIX A - III

III. Drilling Statistics for the United States, Year 1974.

Source: Quarterly Review of Drilling Statistics for the United States, published by the American Petroleum Institute, Vol. VIII, No. 4, April 1975

A. Total Wells Drilled in the United States, Year 1974.

B. Total Exploratory Wells Drilled in the United States, Year 1974.

C. Development Wells Drilled in the United States, Year 1974.

D. Source Agencies for Drilling Statistics.

APPENDIX A - III (cont'd)

Table I

TOTAL WELLS DRILLED IN THE UNITED STATES[1]

1974

State or District	Oil Wells[2] Wells	Oil Wells[2] Footage	Gas Wells[3] Wells	Gas Wells[3] Footage	Dry Holes Wells	Dry Holes Footage
Alabama	16	156,875	16	119,620	66	626,556
Alaska – Onshore	16	122,014	4	11,180	7	67,288
Alaska – Offshore	11	74,880	–	–	–	–
Alaska – Total	27	196,894	4	11,180	7	67,288
Arizona	3	16,004	–	–	8	57,058
Arkansas	99	534,450	41	190,782	177	963,751
California – North	2	3,959	60	319,301	122	720,751
California – Central Coastal	213	745,981	–		55	275,940
California – East Central	1,220	1,975,951	8	30,657	111	530,685
California – South	79	228,788	–	–	16	87,948
California – Offshore	53	162,732	1	2,255	10	30,384
California – Total	1,567	3,117,411	69	352,213	314	1,645,708
Colorado	218	1,315,361	201	1,415,025	417	2,331,513
Florida	9	122,092	–	–	36	419,593
Georgia	–	–	–	–	5	29,755
Idaho	–	–	–	–	2	8,522
Illinois	357	870,144	11	22,651	427	1,099,217
Indiana	136	215,641	21	22,653	219	339,882
Iowa	–	–	–	–	2	3,395
Kansas	989	2,473,604	389	1,133,111	1,312	4,329,554
Kentucky	195	239,141	127	269,779	336	508,336
Louisiana – North	326	915,463	458	1,565,420	387	2,036,733
Louisiana – South	283	2,315,650	190	2,260,796	465	4,917,170
Louisiana – Offshore	216	2,027,092	141	1,568,413	304	2,690,658
Louisiana – Total	825	5,258,205	789	5,394,629	1,156	9,644,561
Maryland	–	–	1	5,120	1	8,119
Michigan	116	605,950	52	284,306	234	1,126,678
Mississippi	67	587,658	26	111,141	349	2,817,916
Missouri	7	768	2	770	23	41,786
Montana	60	272,209	145	269,672	467	1,498,967
Nebraska	40	199,246	5	25,709	185	964,197
Nevada	–	–	–	–	2	18,020
New Mexico – East	297	1,351,146	211	1,922,110	252	1,452,126
New Mexico – West	53	247,473	252	1,145,643	63	249,104
New Mexico – Total	350	1,598,619	463	3,067,753	315	1,701,230
New York	153	186,871	98	287,246	41	154,674
North Carolina	–	–	–	–	11	43,799
North Dakota	42	340,398	–	–	85	607,315
Ohio	567	2,257,315	1,050	4,441,362	171	660,942
Oklahoma	1,149	5,481,703	744	4,869,781	1,164	6,369,870
Pennsylvania	671	728,889	468	1,641,224	69	258,514
South Dakota	1	9,086	–	–	10	53,846
Tennessee	61	90,029	12	18,251	62	106,597
Texas RRC Dist. 1	252	702,113	96	503,419	207	876,662
Texas RRC Dist. 2	77	464,145	290	1,678,902	312	1,859,721
Texas RRC Dist. 3	369	1,764,712	162	1,253,239	412	3,007,483
Texas RRC Dist. 4	230	1,298,075	326	2,261,133	320	1,997,941
Texas RRC Dist. 5	33	134,659	15	144,395	90	497,368
Texas RRC Dist. 6	88	400,218	71	649,611	135	1,020,835
Texas RRC Dist. 7B	444	1,343,016	183	754,019	542	1,728,656
Texas RRC Dist. 7C	414	2,194,060	282	1,846,123	225	1,118,788
Texas RRC Dist. 8	1,058	5,465,121	127	1,528,784	164	1,369,546
Texas RRC Dist. 8A	619	3,216,872	25	111,803	193	1,176,382
Texas RRC Dist. 9	626	1,463,849	100	592,837	401	1,449,475
Texas RRC Dist. 10	191	823,503	145	1,194,567	142	958,738
Texas – Offshore	1	8,886	21	166,919	141	1,156,921
Texas – Total	4,402	19,279,229	1,843	12,685,751	3,284	18,218,516
Utah	118	1,181,851	12	95,686	65	339,294
Virginia	–	–	55	266,809	6	31,074
West Virginia	121	290,716	556	1,669,358	102	359,864
Wyoming	418	2,582,625	40	314,900	530	3,794,677
Gulf of Mexico – Northern[4]	–	–	–	–	14	105,357
Total – 1974	12,784	50,208,984	7,240	38 986,482	11,674	61,355,941

[1] Does not include miscellaneous drilling not related to oil and gas exploration and production.
[2] Includes multiple completion wells which produce gas from one or more zones but oil from at least one zone. (See Tables IV-A and IV-B for detail on multiple completion wells.) A multiple completion well is counted as one well.

APPENDIX A - III (cont'd)

Table I (Cont.)

TOTAL WELLS DRILLED IN THE UNITED STATES[1]

1974

Total Wells Excluding Service Wells, Stratigraphic & Core Tests		Stratigraphic and Core Tests		Service Wells		Total Wells All Types 1974		
Wells	Footage	Wells	Footage	Wells	Footage	Wells	Footage	State or District
98	903,051	–	–	–	–	98	903,051	Alabama
27	200,482	–	–	–	–	27	200,482	Alaska – Onshore
11	74,880	–	–	–	–	11	74,880	Alaska – Offshore
38	275,362	–	–	–	–	38	275,362	Alaska – Total
11	73,062	–	–	–	–	11	73,062	Arizona
317	1,688,983	–	–	3	12,898	320	1,701,881	Arkansas
184	1,044,011	–	–	9	50,430	193	1,094,441	California – North
268	1,021,921	–	–	17	50,761	285	1,072,682	California – Central Coastal
1,339	2,537,293	–	–	130	148,666	1,469	2,685,959	California – East Central
95	316,736	–	–	40	97,262	135	413,998	California – South
64	195,371	–	–	7	23,039	71	218,410	California – Offshore
1,950	5,115,332	–	–	203	370,158	2,153	5,485,490	California – Total
836	5,061,899	–	–	7	43,917	843	5,105,816	Colorado
45	541,685	–	–	3	33,849	48	575,534	Florida
5	29,755	–	–	–	–	5	29,755	Georgia
2	8,522	–	–	–	–	2	8,522	Idaho
795	1,992,012	–	–	28	38,969	823	2,030,981	Illinois
376	578,176	–	–	14	24,533	390	602,709	Indiana
2	3,395	–	–	–	–	2	3,395	Iowa
2,690	7,936,269	37	22,325	98	153,343	2,825	8,111,937	Kansas
658	1,017,256	1	2,036	38	47,224	697	1,066,516	Kentucky
1,171	4,517,616	–	–	38	29,304	1,209	4,546,920	Louisiana – North
938	9,493,616	–	–	3	25,732	941	9,519,348	Louisiana – South
661	6,286,163	–	–	19	156,368	680	6,442,531	Louisiana – Offshore
2,770	20,297,395	–	–	60	211,404	2,830	20,508,799	Louisiana – Total
2	13,239	–	–	–	–	2	13,239	Maryland
402	2,016,934	–	–	12	38,634	414	2,055,568	Michigan
442	3,516,715	–	–	8	45,680	450	3,562,395	Mississippi
32	43,324	69	6,788	–	–	101	50,112	Missouri
672	2,040,848	1	2,893	–	–	673	2,043,741	Montana
230	1,189,152	–	–	–	–	230	1,189,152	Nebraska
2	18,020	–	–	–	–	2	18,020	Nevada
760	4,725,382	–	–	13	62,042	773	4,787,424	New Mexico – East
368	1,642,220	–	–	1	440	369	1,642,660	New Mexico – West
1,128	6,367,602	–	–	14	62,482	1,142	6,430,084	New Mexico – Total
292	628,791	–	–	56	76,473	348	705,264	New York
11	43,799	–	–	–	–	11	43,799	North Carolina
127	947,713	–	–	1	7,935	128	955,648	North Dakota
1,788	7,359,619	1	210	1	4,302	1,790	7,364,131	Ohio
3,057	16,721,354	1	768	131	324,256	3,189	17,046,378	Oklahoma
1,208	2,628,627	8	11,123	106	180,715	1,322	2,820,465	Pennsylvania
11	62,932	–	–	–	–	11	62,932	South Dakota
135	214,877	–	–	–	–	135	214,877	Tennessee
555	2,082,194	–	–	7	18,009	562	2,100,203	Texas RRC Dist. 1
679	4,002,768	–	–	3	15,436	682	4,018,204	Texas RRC Dist. 2
943	6,025,434	–	–	3	1,811	946	6,027,245	Texas RRC Dist. 3
876	5,557,149	–	–	1	4,308	877	5,561,457	Texas RRC Dist. 4
138	776,422	–	–	8	14,726	146	791,148	Texas RRC Dist. 5
294	2,070,664	–	–	17	37,845	311	2,108,509	Texas RRC Dist. 6
1,169	3,825,691	–	–	45	95,638	1,214	3,921,329	Texas RRC Dist. 7B
921	5,158,971	18	27,318	4	15,300	943	5,201,589	Texas RRC Dist. 7C
1,349	8,363,451	1	5,280	43	170,050	1,393	8,538,781	Texas RRC Dist. 8
837	4,505,057	–	–	97	358,242	934	4,863,299	Texas RRC Dist. 8A
1,127	3,506,161	–	–	32	62,119	1,159	3,568,280	Texas RRC Dist. 9
478	2,976,808	–	–	–	–	478	2,976,808	Texas RRC Dist. 10
163	1,332,726	–	–	–	–	163	1,332,726	Texas – Offshore
9,529	50,183,496	19	32,598	260	793,484	9,808	51,009,578	Texas – Total
195	1,616,831	–	–	1	5,869	196	1,622,700	Utah
61	297,883	–	–	–	–	61	297,883	Virginia
779	2,319,938	–	–	1	5,130	780	2,325,068	West Virginia
988	6,692,202	–	–	13	52,788	1,001	6,744,990	Wyoming
14	105,357	–	–	–	–	14	105,357	Gulf of Mexico – Northern[4]
31,698	150,551,407	137	78,741	1,058	2,534,043	32,893	153,164,191	Total – 1974

[3]Includes multiple completion wells which produce gas from all zones. (See Tables IV-A and IV-B for detail on multiple completion wells.) A multiple completion well is counted as one well. Gas wells also include so-called condensate wells.

[4]See footnote 4, page 3.

APPENDIX A - III (cont'd)

Table II

TOTAL EXPLORATORY WELLS DRILLED IN THE UNITED STATES

1974

State or District	Oil Wells[1]		Gas Wells[2]		Dry Holes		Total Exploratory Wells	
	Wells	Footage	Wells	Footage	Wells	Footage	Wells	Footage
Alabama	5	66,516	4	10,410	49	465,207	58	542,133
Alaska – Onshore	2	18,930	3	8,830	7	67,288	12	95,048
Alaska – Offshore	–	–	–	–	–	–	–	–
Alaska – Total	2	18,930	3	8,830	7	67,288	12	95,048
Arizona	–	–	–	–	5	38,939	5	38,939
Arkansas	8	60,358	2	11,024	80	479,864	90	551,246
California – North	–	–	16	81,121	77	462,349	93	543,470
California – Central Coastal	11	64,686	–	–	41	223,795	52	288,481
California – East Central	12	69,844	–	–	62	369,669	74	439,513
California – South	3	6,793	–	–	7	45,880	10	52,673
California – Offshore	2	5,792	–	–	4	25,399	6	31,191
California – Total	28	147,115	16	81,121	191	1,127,092	235	1,355,328
Colorado	25	152,056	26	168,544	287	1,621,847	338	1,942,447
Florida	2	23,281	–	–	28	296,705	30	319,986
Georgia	–	–	–	–	5	29,755	5	29,755
Idaho	–	–	–	–	2	8,522	2	8,522
Illinois	25	65,089	3	5,351	192	505,926	220	576,366
Indiana	18	39,493	6	8,390	144	216,125	168	264,008
Iowa	–	–	–	–	2	3,395	2	3,395
Kansas	98	390,458	33	115,096	716	2,402,565	847	2,908,119
Kentucky	24	32,096	20	44,040	140	235,443	184	311,579
Louisiana – North	8	65,839	22	152,499	189	1,159,365	219	1,377,703
Louisiana – South	15	179,778	38	543,339	223	2,706,953	276	3,430,070
Louisiana – Offshore	1	8,162	1	16,181	149	1,179,830	151	1,204,173
Louisiana – Total	24	253,779	61	712,019	561	5,046,148	646	6,011,946
Maryland	–	–	1	5,120	1	8,119	2	13,239
Michigan	50	272,933	34	192,189	174	826,993	258	1,292,115
Mississippi	23	228,641	6	49,773	263	2,203,944	292	2,482,358
Missouri	–	–	1	360	23	41,786	24	42,146
Montana	10	71,184	35	67,571	336	1,171,884	381	1,310,639
Nebraska	13	67,088	3	14,720	139	712,058	155	793,866
Nevada	–	–	–	–	2	18,020	2	18,020
New Mexico – East	6	54,544	46	402,851	116	588,716	168	1,046,111
New Mexico – West	2	11,694	2	8,729	37	152,377	41	172,800
New Mexico – Total	8	66,238	48	411,580	153	741,093	209	1,218,911
New York	–	–	19	67,113	30	123,499	49	190,612
North Carolina	–	–	–	–	11	43,799	11	43,799
North Dakota	11	75,996	–	–	63	447,162	74	523,158
Ohio	20	105,369	117	507,792	35	166,632	172	779,793
Oklahoma	51	356,126	61	540,727	284	1,777,911	396	2,674,764
Pennsylvania	11	14,851	42	168,573	48	221,999	101	405,423
South Dakota	–	–	–	–	9	46,332	9	46,332
Tennessee	17	25,105	11	16,676	57	98,702	85	140,483
Texas RRC Dist. 1	10	41,609	29	154,207	149	675,744	188	871,560
Texas RRC Dist. 2	21	137,480	142	882,455	213	1,352,621	376	2,372,556
Texas RRC Dist. 3	36	327,349	104	877,073	286	2,393,026	426	3,597,448
Texas RRC Dist. 4	24	151,593	86	618,004	197	1,307,731	307	2,077,328
Texas RRC Dist. 5	3	27,698	9	84,790	68	439,928	80	552,416
Texas RRC Dist. 6	5	44,124	16	153,955	101	779,552	122	977,631
Texas RRC Dist. 7B	29	118,966	44	173,949	288	1,102,936	361	1,395,851
Texas RRC Dist. 7C	28	153,201	25	138,041	142	712,861	195	1,004,103
Texas RRC Dist. 8	37	284,064	31	394,973	89	768,871	157	1,447,908
Texas RRC Dist. 8A	23	172,477	–	–	119	782,431	142	954,908
Texas RRC Dist. 9	56	266,045	48	272,221	213	985,131	317	1,523,397
Texas RRC Dist. 10	6	65,086	16	169,963	64	534,929	86	769,978
Texas – Offshore	–	–	12	89,774	138	1,131,494	150	1,221,268
Texas – Total	278	1,789,692	562	4,009,405	2,067	12,967,255	2,907	18,766,352
Utah	4	48,696	4	35,660	48	283,355	56	367,711
Virginia	–	–	5	26,053	3	17,532	8	43,585
West Virginia	5	12,651	53	207,262	44	179,366	102	399,279
Wyoming	54	468,518	19	188,264	397	2,988,203	470	3,644,985
Gulf of Mexico – Northern[3]	–	–	–	–	14	105,357	14	105,357
Total – 1974	814	4,852,259	1,195	7,673,663	6,610	37,735,822	8,619	50,261,744

[1]Includes multiple completion wells which produce gas from one or more zones but oil from at least one zone. (See Table IV-A for detail on multiple completion wells.)
[2]Includes multiple completion wells which produce gas from all zones. (See Table IV-A for detail on multiple completion wells.) Gas wells also include so-called condensate wells.
[3]See footnote 4, page 3.

APPENDIX A - III (cont'd)

Table III
DEVELOPMENT WELLS DRILLED IN THE UNITED STATES
1974

State or District	Oil Wells[1]		Gas Wells[2]		Dry Holes		Total Development Wells	
	Wells	Footage	Wells	Footage	Wells	Footage	Wells	Footage
Alabama	11	90,359	12	109,210	17	161,349	40	360,918
Alaska – Onshore	14	103,084	1	2,350	–	–	15	105,434
Alaska – Offshore	11	74,880	–	–	–	–	11	74,880
Alaska – Total	25	177,964	1	2,350	–	–	26	180,314
Arizona	3	16,004	–	–	3	18,119	6	34,123
Arkansas	91	474,092	39	179,758	97	483,887	227	1,137,737
California – North	2	3,959	44	238,180	45	258,402	91	500,541
California – Central Coastal	202	681,295	–	–	14	52,145	216	733,440
California – East Central	1,208	1,906,107	8	30,657	49	161,016	1,265	2,097,780
California – South	76	221,995	–	–	9	42,068	85	264,063
California – Offshore	51	156,940	1	2,255	6	4,985	58	164,180
California – Total	1,539	2,970,296	53	271,092	123	518,616	1,715	3,760,004
Colorado	193	1,163,305	175	1,246,481	130	709,666	498	3,119,452
Florida	7	98,811	–	–	8	122,888	15	221,699
Georgia	–	–	–	–	–	–	–	–
Idaho	–	–	–	–	–	–	–	–
Illinois	332	805,055	8	17,300	235	593,291	575	1,415,646
Indiana	118	176,148	15	14,263	75	123,757	208	314,168
Iowa	–	–	–	–	–	–	–	–
Kansas	891	2,083,146	356	1,018,015	596	1,926,989	1,843	5,028,150
Kentucky	171	207,045	107	225,739	196	272,893	474	705,677
Louisiana – North	318	849,624	436	1,412,921	198	877,368	952	3,139,913
Louisiana – South	268	2,135,872	152	1,717,457	242	2,210,217	662	6,063,546
Louisiana – Offshore	215	2,018,930	140	1,552,232	155	1,510,828	510	5,081,990
Louisiana – Total	801	5,004,426	728	4,682,610	595	4,598,413	2,124	14,285,449
Maryland	–	–	–	–	–	–	–	–
Michigan	66	333,017	18	92,117	60	299,685	144	724,819
Mississippi	44	359,017	20	61,368	86	613,972	150	1,034,357
Missouri	7	768	1	410	–	–	8	1,178
Montana	50	201,025	110	202,101	131	327,083	291	730,209
Nebraska	27	132,158	2	10,989	46	252,139	75	395,286
Nevada	–	–	–	–	–	–	–	–
New Mexico – East	291	1,296,602	165	1,519,259	136	863,410	592	3,679,271
New Mexico – West	51	235,779	250	1,136,914	26	96,727	327	1,469,420
New Mexico – Total	342	1,532,381	415	2,656,173	162	960,137	919	5,148,691
New York	153	186,871	79	220,133	11	31,175	243	438,179
North Carolina	–	–	–	–	–	–	–	–
North Dakota	31	264,402	–	–	22	160,153	53	424,555
Ohio	547	2,151,946	933	3,933,570	136	494,310	1,616	6,579,826
Oklahoma	1,098	5,125,577	683	4,329,054	880	4,591,959	2,661	14,046,590
Pennsylvania	660	714,038	426	1,472,651	21	36,515	1,107	2,223,204
South Dakota	1	9,086	–	–	1	7,514	2	16,600
Tennessee	44	64,924	1	1,575	5	7,895	50	74,394
Texas RRC Dist. 1	242	660,504	67	349,212	58	200,918	367	1,210,634
Texas RRC Dist. 2	56	326,665	148	796,447	99	507,100	303	1,630,212
Texas RRC Dist. 3	333	1,437,363	58	376,166	126	614,457	517	2,427,986
Texas RRC Dist. 4	206	1,146,482	240	1,643,129	123	690,210	569	3,479,821
Texas RRC Dist. 5	30	106,961	6	59,605	22	57,440	58	224,006
Texas RRC Dist. 6	83	356,094	55	495,656	34	241,283	172	1,093,033
Texas RRC Dist. 7B	415	1,224,050	139	580,070	254	625,720	808	2,429,840
Texas RRC Dist. 7C	386	2,040,859	257	1,708,082	83	405,927	726	4,154,868
Texas RRC Dist. 8	1,021	5,181,057	96	1,133,811	75	600,675	1,192	6,915,543
Texas RRC Dist. 8A	596	3,044,395	25	111,803	74	393,951	695	3,550,149
Texas RRC Dist. 9	570	1,197,804	52	320,616	188	464,344	810	1,982,764
Texas RRC Dist. 10	185	758,417	129	1,024,604	78	423,809	392	2,206,830
Texas – Offshore	1	8,886	9	77,145	3	25,427	13	111,458
Texas – Total	4,124	17,489,537	1,281	8,676,346	1,217	5,251,261	6,622	31,417,144
Utah	114	1,133,155	8	60,026	17	55,939	139	1,249,120
Virginia	–	–	50	240,756	3	13,542	53	254,298
West Virginia	116	278,065	503	1,462,096	58	180,498	677	1,920,659
Wyoming	364	2,114,107	21	126,636	133	806,474	518	3,047,217
Gulf of Mexico – Northern[3]	–	–	–	–	–	–	–	–
Total – 1974	11,970	45,356,725	6,045	31,312,819	5,064	23,620,119	23,079	100,289,663

[1] Includes multiple completion wells which produce gas from one or more zones but oil from at least one zone. (See Table IV-B for detail on multiple completion wells.)

[2] Includes multiple completion wells which produce gas from all zones. (See Table IV-B for detail on multiple completion wells.) Gas wells also include so-called condensate wells.

[3] See footnote 4, page 3.

APPENDIX B

I. Typical Crude Oil Price at the Well, Years 1955 through 1975 (First Quarter).

I. Sales of Producing Properties and Drilling Equipment, Years 1955 through 1973 (United States)

LA RUE, MOORE & SCHAFER

APPENDIX B - I

TYPICAL CRUDE OIL PRICE AT THE WELL
YEARS 1955 THROUGH 1975 (FIRST QUARTER)

Year	Price (a)
1955	$ 2.90
1956	2.90
1957	3.25
1958	3.25
1959	3.25
1960	3.25
1961	3.20
1962	3.10
1963	3.10
1964	3.10
1965	3.10
1966	3.11
1967	3.11
1968	3.16
1969	3.32
1970	3.40
1971	3.60
1972	3.60
4/73	3.85
8/73	4.20
12/73	5.20
1/74	10.00
9/74	10.60
11/74	10.60
1/75	11.20
2/75	11.60
3/75	12.00

(a) East Texas Field (new oil).

APPENDIX B - II

SALES OF PRODUCING PROPERTIES
AND DRILLING EQUIPMENT
YEARS 1955 THROUGH 1973
(United States)

Year	(1) No. of Drilling Rigs Sold at Auction	(2) No. of Sales of Companies to International Oil Companies
1955		0
1956		11
1957		5
1958		11
1959		11
1960	13(a)	18
1961	45	20
1962	170	20
1963	238	8
1964	279	16
1965	265	11
1966	269	5
1967	242	6
1968	274	2
1969	200	1
1970	234	2(b)
1971	168	
1972	135	
1973	101(b)	
TOTALS	2,633	147

(a) First auction.
(b) Last available data.

Column (1) - Source: American Association of Oilwell Drilling Contractors.
Column (2) - Source: Concentration Levels and Trends, January 1974, Federal Trade Commission.

STATEMENT OF HENRY M. JACKSON ON ROBERT NATHAN'S TESTIMONY ON OIL PRICES

[From the Congressional Record, July 16, 1975]

On April 28, 1975 Robert R. Nathan testified before the Senate Interior and Insular Affairs Committee on national pricing policy for new domestic crude oil. Nathan reported the results of a study conducted by a Dallas petroleum consulting firm, La Rue, Moore and Schafer, which purported to show that the "economic cost" of new oil in the United States in 1974 was as high as $12.73 per barrel.

The staff of the Senate Interior Committee, with the assistance of the Congressional Research Service, has analyzed both the LaRue, Moore and Schafer Study and the policy conclusion which Nathan either claims explicitly or implies on the basis of that study. A copy of the Interior Committee staff analysis is printed below. The results of this analysis stand in stark contrast to the Nathan testimony and raise the most serious and substantial doubts concerning the validity of the study and of the policy conclusions drawn from it.

It is clear that the Administration, the oil industry, and their supporters in the Congress have attempted over the past two months to use the Nathan testimony as "proof" of the need for domestic oil prices set at levels even higher than those imposed by the OPEC cartel. In my opinion, the Interior Committee staff analysis of the Nathan testimony utterly demolishes the foundation of any such claim based on the arguments of the LaRue, Moore and Schafer study.

A number of misconceptions and outright distortions are contained in the Nathan testimony and the study upon which it is based. In addition, even more egregious distortions have characterized the interpretations which others have placed on the testimony.

Some of the more significant and telling points which the Interior Committee staff analysis makes about the Nathan study are:

First, the prices which are calculated by LaRue, Moore and Schafer by far exceed the prices determined by other reputable analyses, including those by the National Petroleum Council and the Federal Energy Administration's Project Independence Task Force.

Second, in calculating their "prices" LaRue, Moore and Schafer have consistently overestimated dollar outlays—for example, by assuming an after-tax rate of return which is two and one-half times the average for U.S. manufacturing—and underestimated the amount of oil which is obtained from those outlays—for example, by totally ignoring the enormous low-cost reserves discovered in Alaska.

Third, independent of the magnitude of the prices calculated, the conclusions drawn from this effort could be applied only to a fraction of what is presently called new oil. The LaRue, Moore and Schafer study only addresses the question of pricing for newly discovered oil. It provides no standard for pricing of the other categories of crude oil production established by current regulations—old

oil, released oil, or stripper well oil. It does not even claim to provide a guide to the price necessary to elicit new oil from old reservoirs by secondary and tertiary recovery.

Fourth, the logic of the study, if carried to its conclusion, would imply that the U.S. should adopt a cost-based formula which sets a separate price for oil discovered in each past and future year, and perhaps for every geographic region. This sort of regulation would extend to its logical absurdity the regime that now applies to interstate natural gas under the Federal Power Commission. I doubt that the oil industry representatives who have been urging Nathan's analysis on members of Congress really intend that Congress draw this implication; and

Finally, the LaRue, Moore and Schafer analysis is totally unable to relate a particular crude oil price to the level of production which would be forthcoming at that price. That is, of course, what is really required for the purpose of evaluating the appropriateness of a new oil price. To my knowledge, no adequate analysis of this sort exists. The efforts of Nathan and of LaRue, Moore and Schafer, however, because of their total inadequacy, only serve to further confuse the oil pricing issue.

The calculation by LaRue, Moore and Schafer is an interesting academic exercise which is unfortunately fatally tilted toward the substantial overestimation of the "prices" required to make oil exploration profitable. The oil industry and the Administration have been all too eager to find some justification, no matter how meager, for the economically ruinous oil prices which are implied by their policies—in combination with those of OPEC. The LaRue, Moore and Schafer study and the interpretations of it given by Robert Nathan and others far less scrupulous fail totally to provide this justification. There is indeed a widespread conviction even in the Administration, as evidenced by statements of FEA Administrator Zarb, Secretary Simon and others, that such prices are neither necessary nor justified as production incentives.

The "Economic Cost" of Crude Oil, a Comment on Analysis by Robert R. Nathan and LaRue, Moore and Schafer

By Arlon R. Tussing with Benjamin S. Cooper and Henry Canaday. May, 1975

SUMMARY

In testimony on oil pricing policy before the Senate Committee on Interior and Insular Affairs on April 28, 1975, Robert R. Nathan presented calculations of the "economic price" of crude oil production for the years 1959 through 1974. This "economic price" purported to be the "price necessary to induce wildcat producers to take risks and incur the costs attendant on finding and developing new sources of crude oil." This price ranged, according to Nathan, from $2.86 per barrel in 1959 to $8.22 in 1970 and $12.73 in 1974.

Using this set of price estimates Nathan concludes:

> "It is quite clear that for some time oil prices in the United States have been at levels well below actual costs and this has had a discouraging impact on finding and developing new sources of oil supplies", and . . .

"It costs a great deal more to find, develop and produce oil today than ever in the past. If this nation is serious about reducing dependence on oil imported from insecure sources it will have to pay sufficient prices to cover the true economic costs of exploration, discovery, development, and production."

Without explicitly saying so, Nathan implies that these "economic osts" are now at a level *in excess of* $12.73 per barrel.

The Nathan testimony is based on a study carried out by LaRue, [oore & Schafer, a Dallas, Tex. petroleum consulting firm. Both the athan testimony and the study by LaRue, Moore & Schafer have een carefully analyzed by the staff of the Senate Interior Committee ith the assistance of the Congressional Research Service.

Our principal conclusions are:

1. *The logical implication of the Nathan testimony is that the nited States should establish a system of cost-based regulation for etroleum pricing similar to the present Federal Power Commission gulation of interstate sales of natural gas.*

There are substantial conceptual flaws in the LaRue, Moore & chafer study upon which the Nathan testimony is based, flaws which e compounded by a consistent bias in the assumptions of, and choice data for, the calculations. If, however, for the sake of argument, ese are ignored, and the numerical results accepted, the logic of athan's exercise suggests that a cost based system of oil pricing be nposed with a different price for oil discovered in each given year. arried to its conclusion, the resulting multi-tier system for newly scovered oil would also differentiate prices regionally, between on-ore and off-shore production, and among classes of producers.

Despite this implication of Nathan's testimony, the LaRue, Moore Schafer study does not, in fact, distinguish "economic prices" for y specific region or category or of production but is in fact based national averages modified only by the exclusion of prolific and latively low cost reserves of northern Alaska.

Accordingly the study does not specify either the appropriate price r production classified under current regulations variously as old l, released oil or stripper well oil, or an appropriate price that might provided for oil produced with the assistance of secondary or rtiary recovery.

2. *If Nathan's interpretation of LaRue, Moore & Schafer is correct, e oil industry's investment strategy for the past 15 years has been tremely foolish.*

Nathan's finding, "that for some time oil prices have been at levels low actual costs," is puzzling on its face, because it implies that the troleum industry voluntarily poured $64 billion over the period of 59–1974 into investments that would not earn an economic rate of turn.

3. *Nathan's results substantially exceed previous calculations of oil sts by reputable sources.*

The numerical results of the study far exceed the "economic" or equired" price estimates arrived at for the same years by both public d private studies, including those of Franklin Fisher, Foster

Associates, the Bureau of Mines,[1] the National Petroleum Council ar the Federal Energy Administration's Project Independence stud

4. *The LaRue, Moore and Schafer calculations of the costs whi should be reflected in oil prices include huge lease payments, unrea*

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[1] *Crude oil cost estimates based upon historic data.* The Foster Associates Report, "T Role of Petroleum and Natural Gas from the Outer Continental Shelf in the National Su ply of Petroleum and Natural Gas" (Washington: U.S. Government Printing Office, 197 shows estimated "current costs" of new hydrocarbon supplies from 1958–67 data. " 'current cost' (was) meant the cost which may reasonably be anticipated in the near-te future in the absence of significant changes in discovery rates or other factors influenci unit costs. The essence of the measurement of current cost is to estimate two categor of costs—those of (1) finding and (2) producing the reserves." The cost estimates f oil reservoirs are shown below:

	Gulf of Mexico	Onshore Southern Louisiana	Ot Continen United Sta
Finding costs	$1.30–1.35	$1.19	$1
Other costs	.63	.91	
Total	1.93–1.938	2.20	1

These figures include lease acquisition expenses and dry hole costs, but do not inclu a return to capital, royalties or income tax. The study used a discounted cash flow (DC model to determine the overall rate of return from crude oil at the prices prevailing the time. Investment in oil reservoirs earned a DCF rate of return (on total investmen of 5 to 6.4 percent, and a return to book capital of 7.2 to 11.9 percent (see footnotes and 5 for a discussion of competitive rates of return).

In 1970 the Bureau of Mines analyzed seven fields selected at random in the Gulf Mexico by the DCF method. The total cost of crude oil, excluding dry hole costs oth than on the particular lease block, and profits, but including lease bonuses, royalties a income taxes, ranged from $1.45 per barrel to $2.56. Profit per barrel, based upon p vailing prices (1970) ranged from .32 cents to $1.31, for a DCF rate of return varyi from 1.1 percent to 19.5 percent. (Bureau of Mines Information Circular No. 8557, 197

[2] *Recent estimates of the "economic price" or cost of new crude oil.* Judgments regar ing oil prices in the National Petroleum Council's (NPC's) *Energy Outlook* study, t Federal Energy Administration's (FEA's) *Project Independence Report* and the Mas chusetts Institute of Technology's (M.I.T.'s) *Economic Evaluation* of Project Independen are all based upon a balance sheet type approaches similar in one key regard to that LaRue, Shafer & Moore. Neither the NPC nor FEA model uses an economic model th takes account of the fact that costs per barrel (both incremental and average) would fact vary greatly, *depending upon the levels of production.* Both approaches project *average* cost of crude oil per barrel for a particular *assumed level of production.* The FE and MIT reports start from such a single point, balance sheet-type estimate of avera prices, and adjust it with a price elasticity of supply coefficient (the ratio between t percentage change in output and the percentage change in price) in order to project t daily rate of production at different price levels.

The NPC, FEA and MIT prices purportedly refer to the average cost of *all futu production* from both present and future reserves as seen from a given future producti year. The Nathan figures, on the contrary, refer to *all production from reservoirs discover in each particular year* in the recent past, as seen from that year. None of these concep is necessarily equivalent either to the price industry must receive today, or to the pri industry must expect to receive in some future year, to assure a specified level of pr duction in that year.

Nathan's concept of "economic price" purportedly refers to a cost for discovery a producing new reserves actually added in a particular year, and not necessarily to t cost for the reserves we would have *desired* to have added and produced. In order compare his estimates with those in other studies that post different levels of producti the prices which are in principle most comparable to Nathan's are those that res in the similar levels of production to those which actually occurred (in 1974, for exampl

In FEA's "business as usual" (BAU) scenario, $7 per barrel (in 1973 dollars) is "minimum acceptable price" that would result in production increases for domes petroleum liquids of 6 and 10 percent over 1974, in 1980 and 1985 respectively. In t "accelerated development" scenario (where the critical changes are expanded leasi authority to develop Naval Petroleum Reserve No. 4, and deregulation of new natu gas), the "minimum acceptable price" necessary to maintain current production is *l than $4 per barrel* (in 1973 dollars)! Four dollars would, according to the projectio generate an increase in production over 1974 of 6 and 13 percent in 1980 and 1985 spectively. (*Project Independence Report*, November 1974, P. 81.)

FEA's 1980 and 1985 production estimates (11.1 to 11.9 million barrels per day) $4 and $7 per barrel are not likely to be regarded as an acceptable degree of energy se sufficiency. On that basis, the desirable price level is of course higher than $4 or $7. B a strict reading of the LaRue, Moore & Schafer analysis does not show a claim that $12. (in 1974 dollars, we assume) is the *proper price* for crude oil, but that it was the "econom price" (cost) of the *discoveries actually made in 1974.* (Nathan, however, attempts convey the former inference.) Because these additions were clearly *insufficient* to repla 1974 consumption, the study's figures imply that any desired *increase* in discoveri

stically high rates of return for the oil industry and exclude the low-ost reserves associated with the most favorable domestic discovery of the last 15 years.

The surprisingly high figures which Nathan quotes from the LaRue, Moore & Schafer study trace directly to a number of assumptions. Among the most important:

The inclusion in petroleum capital costs of lease bonus payments which, if Nathan's findings are correct, were unwise in the past and would be unnecessary in the future;

Treatment of petroleum reserve data that ignores both the true cost of developing each year's reserve additions and the flexibility of producible reserves at differing price levels;

The assumption of a rate of return standard—15 percent on total assets after taxes—in substantial excess of both the experience of other American industries and the profitability premised in other energy development research. This extreme assumption compounds annually into Nathan's "economic price" over the 28 years of each reserve's productive life; and

The deliberate exclusion from the study of all data on oil discoveries on the North Slope of Alaska. At one stroke, Nathan thus removes the largest single field of petroleum development

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vould require an even higher price than $12.73 over the life of any new crude oil reserves dded in the future.

The NPC in its 1973 study of oil availability (reflecting work begun in 1971) gave he price figures in the left column of the following table. The figures in the right column how the NPC estimates, updated to curent prices by use of the GNP deflator. (The ears after 1975 are in constant 1975 dollars.)

	Unit revenue required—	
	1970 dollars	Current dollars
1971	3.22	3.37
1972	3.31	3.58
1973	3.37	3.85
1974	3.49	4.39
1975	3.65	5.14
1980	4.90	6.90
1985	6.69	9.42

The NPC "required price" figures are for *all* oil, and are therefore a weighted average f "old" and "new" oil, rather than oil from reserves discovered only in the particular ear (as in the case of Nathan's study). They can, however, be further adjusted to eparate out a "required price" for new oil, which would be comparable to the Nathan gure. Assuming that the price of "old" oil including "old" stripper well oil and presently released" oil from old wells, were frozen at $5.25, that the production of old oil declined t 10 percent per year, and that total production remained unchanged over time, the equired price for new oil would have been less than $5.25 per barrel in current prices or each year through 1975; for 1980 it would be $8.14 per barrel, and for 1985, $10.81 both in 1975 dollars).

M.I.T.'s report (*Energy Self-Sufficiency: An Economic Evaluation*, May 1974) implies iat the cost of "new" oil to maintain the volumes that have actually been produced in ecent years is in the vicinity of $7 per barrel (1974 dollars). That price, according the Erickson-Spann model, would result in 1980 crude oil production of 8.4 million arrels per day; an MIT natural gas supply model predicts 2.1 million barrels per day f natural gas liquids at this price, for a total of 10.5 million barrels per day—just bout the 1974 average for domestic production. Here again, "only" 10.5 million barrels er day of domestic production would generally be regarded as inadequate because it nplies a continuing growth of oil imports. The MIT report suggests that, for total energy lf-sufficiency, however, ". . . the price needed to bring in 13 million barrels per day 1980 . . . must be far higher than the $5.64 estimated by the NPC. We might suppose iat to *double the 1972–73 performance* (in terms of reserve additions) would require ipling the price . . . to $12.90 in 1973 dollars." (emphasis added). The similarity here the Nathan figure is purely coincidental—because the MIT study implies that $12.90 er barrel will result in the future in *twice* the discoveries which that price, according Nathan, would have supported in 1974. The point of the foregoing is not that the ojections of FEA, NPC or MIT are correct, or even better than Nathan's, but to lustrate the substantial divergence of his numbers over those recently produced by her authorities, given similar assumptions about the level of production.

and reduces total reserve additions in the United States over t
last eight years by more than one-half.

5. *The Nathan testimony does not, and cannot, identify the app*
priate price for domestic oil.

Even if the biases listed above were corrected, the notion of "e
nomic price" as defined by LaRue, Moore and Schafer cannot be ma
relevant to a determination of the proper level for new oil prices
the future. Any meaningful attempt to determine the true supp
function for petroleum would have to combine an estimate of h
much oil is wanted at various prices with an estimate of how mu
could be produced at each of those prices. Because the LaRue, Moo
& Schafer model does not even consider the relationship between t
volume of oil that can be discovered and produced at different lev
of cost, it has nothing useful to say about the proper or desirable le
of crude oil prices.

ANALYSIS

Mr. Nathan's prepared statement for the Senate Interior Commi
tee hearings of April 28, 1975, "The Cost of Finding, Developing a
Producing Crude Oil in the United States," draws conclusions fro
and makes policy recommendations based upon, an analysis of t
oil industry's financial and operating data entitled "Calculation
New Oil Costs: United States, Years 1959 through 1974." The analys
was prepared by LaRue, Moore & Schafter, a Dallas-based petroleu
consulting firm. There are substantial reasons to doubt the inferenc
which Nathan makes from the LaRue, Moore and Schafer study, a
there are substantial reasons to question the methodology, use
data and, finally, the value of the study itself.

The LaRue, Moore & Schafer Calculations

The LaRue, Moore & Schafer approach can be quickly sketche
Data on the costs of finding oil, estimates of the amounts found, a
prospective costs of producing it (including royalties, Federal a
State taxes, etc.) are presented for each year 1959 to 1974. A d
counted cash flow (DCF) model is then used to set the price (called t
economic price) which would provide the producers with an annu
after-tax return of 15 percent on their total investment (including i
vestments made with borrowed funds). The method is comparable
those used by corporate planners in assessing the likely profitability
a potential investment—except that in this case the bulk of investme
exploration and development expense has already been made. W
its assumptions accurate, the method would be equivalent to a yea
end review by petroleum investors of the capital costs incurred du
ing the preceding twelve months and the benefits needed to justi
their prior expenditures.

The study in no fashion assesses the profitability of oil producti
during each of the years in the table. The vast majority of oil actua
lifted in any particular year is from reserves developed in earlier a
less expensive periods. For this reason, the industry could conceivab
make a competitive profit in every year and on every investment pr
ect, with the current price *always* lagging behind the "economic pric
calculated for current investments. Nathan's statement "that for so
time oil prices in the United States have been at levels well bel
actual costs," is not, therefore, a legitimate inference from the LaR
Moore & Schafer report.

Even as an intended estimate of "minimum economic price" 'athan's definition) for current year development, moreover, the La- ie, Moore & Schafer report rests on incorrect or inappropriate as- nptions. These shortcomings in turn impart substantial upward ises to its price projections.

Leasehold Costs

The cost of acquiring leases—including bonus payments—is in- ded in the original investment total on which the 15 percent annual urn must be earned. From an oil producer's point of view, this uld be a legitimate procedure for deciding, among other things, ether a *past* bid offer was justified. From the standpoint of the nomy as a whole this assumption reduces to the assertion that con- ners must pay a price for oil that rewards landowners with what- er bonuses and other payments oil developers happen to offer them. these payments reflected a realistic estimate of the property's al- native uses, they would indeed constitute an "economic cost" useful arriving at an "economic price" for oil. But when, as in the majority cases, they reflect only a scarcity bid by prospective producers, they a transfer payment—useful as an allocative mechanism but un- essary as a *cost* either to society or to the producers who make them. Put another way, the willingness to incur lease acquisition charges evidence that producers anticipate that prices over the life of the se will in fact *exceed* the expected costs of exploring, developing l producing it—including the appropriate allowance for dry holes. a particular price level would not adequately compensate pro- cers for their original lease acquisition expenses, then these expenses mselves should and would be revised downward before oil prices d increase. The LaRue, Moore & Schafer analysis purports to show vailing price levels failing to justify productive investment, yet eals producers continually incurring leasehold expenses of up to percent of their investment. In 1970, for example, exclusion of only sehold costs would reduce the "economic price" projection by about 30 per barrel, from $7.25 to less than $6.00.

Treatment of Natural Gas

The model assumes natural gas prices at a fixed figure for each year ial to 1.5 times the Bureau of Mines estimate of the average price natural gas in that year. For recent years, the resulting figure is far s than producers can actually expect to receive over the life of newly led gas reserves. It is believable, for instance, that production from erves added in 1973 and 1974 will be selling for only 28 and 45 ts respectively per thousand cubic feet (Mcf) over the life of these erves? The average price of natural gas in intrastate sales in 1974 s already over $1.00 per Mcf. By seriously understating revenues ducers can anticipate from natural gas sales, the methodology con- ently inflates the revenues they must receive from crude oil to as- e a specified profitability for their investment.

The LaRue, Moore & Schafer analysis also takes no accounting of ne joint costs of oil and natural gas. Estimates of oil development l operating costs from the American Petroleum Institute's *Joint sociation Survey of the Oil and Gas Producing Industry*—are de- ed from aggregates that reflect the expenses of oil and gas opera- ns *together*. It appears that exploratory expenses from this source ributed by LaRue, Moore & Schafer to the search for oil—includ-

ing dry hole expenses—have also been responsible for the discovery of non-associated natural gas reserves in addition to oil and associated natural gas. Revenues from non-associated gas, however, are no included as income in the analysis.

The formula by which LaRue, Moore & Schafer separated out the cost of oil development may, moreover, tend to underestimate oi operating costs and overestimate oil exploratory and development outlays. This latter component, because it must compound at 15 percent until the product is sold, is the far more decisive factor in setting the economic price.

3. Use of Reserve Figures

The figure used for gross reserve additions in each year is not the whole increase in proved reserves as published by the American Petroleum Institute, but only the reserves attributed to new discoveries and "expected upward revisions." Each year's expenditure figures however, includes all exploration and development outlays in that year. The cash-flow purportedly necessary to produce each year's new reserves, therefore, encompasses development investment that results in current year extensions and upward revisions of reserve estimates for previously discovered fields, including investment in secondary and tertiary recovery. The result can be viewed as either a gross understatement of new reserves or a gross overstatement of the investment necessary to discover them. In either view, the result is a strong upward tilt to price projections for recent years. Though there is no simple means of disentangling these mismatched reserve and cost data, the case of 1973 is instructive of its impact. Taking LaRue, Moore & Schafer's version of investment during that year with 1973's addition to proved reserves recorded by the American Petroleum Institute would reduce the "economic price" from $8.70 per barrel to about $6.00

4. Critique of API Reserve Estimates

Even this adjustment would not resolve another fundamental problem with the model's approach to crude oil reserves. For the API reserve figures—whether taken in their original form or as converted and reassigned by LaRue, Moore & Schafer—have not been adjusted to take into account higher price levels. This is despite the qualification in the definition of provided reserves that they be recoverable under "current economic conditions." Higher priced crude oil makes possible better and more widely applied recovery techniques. Revenues from crude oil at $10 per barrel or more, first, extend the productive life of previously discovered reservoirs, and thereby increase the amount of the recoverable oil contained in them.

Price can be expected to influence the volume of reserves, second, by making feasible more advanced methods of recovery, and third by its effect on the very definition of a successful drilling venture. Among the historical "dry holes"—whose cost pushes up the total capital commitment required for developing reserves—are many wells that reached crude oil reservoirs of insufficient size or quality to justify development at $3.00 per barrel. At higher crude oil prices these marginal reservoirs become additions to the nation's producible oil reserves.

The Nathan study, by failing to allow flexibility of reserves in response to real or expected price increases, built a decisive bias into the economic price estimates themselves. For these "prices" are essentially a gross revenue (needed to recover capital and costs), divided

y the estimated volume of product to be sold. Improperly conserva-ve estimates of the amount of oil that is recoverable increase the ollar burden that each barrel must bear in justifying investments.

. *The Rate of Return*

A 15 percent after-tax rate of return [3] on stockholders' equity may e a reasonable standard for judging new investments. Such a stand-rd reflects the anticipated rate of return on alternative investment pportunities. Over the period 1966–1974, the average rate of return or Fortune's top 500 U.S. manufacturing firms was 11.3 percent, eaching a peak of 15.5 percent in 1974. The LaRue, Moore & Schafer xercise relied upon by Nathan, however, uses as its standard not a 5 percent rate of return on stockholders' equity by a 15 percent after-ax rate of return *on total assets*. This figure is almost two and one-alf times the average for the comparable rate of return concept in J.S. manufacturing industry over the period in question (6.2 per-ent between 1966 and 1974).[4]

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[3] *Real or Nominal Rates of Return.* Nathan's study did not explicitly designate this ate either as a "real" rate of return—i.e., one that removes the overstatement of infla-ion—or simply a nominal one expressed in current dollars. If it is supposed to be a real" return, its profitability target would be all the more excessive. Fifteen percent per nnum is about five times the real return on secure investments such as mortgaged roperty and the AAA debentures by which major oil firms themselves borrow money. et if it is to be merely a nominal return it makes no sense to compare the model's economic price" to the then prevailing crude oil price—investors would expect this latter rice to rise with inflation, assuring them of the required nominal rate of return, and ancelling the whole logic of Nathan's approach.

[4] *Rate of Return Standards.* The table below shows some rate of return indicators for ll U.S. manufacturing industry. None of these book rate of return concepts corresponds xactly to a DCF rate of return; for relatively capital-intensive industries, and in in-ationary periods generally book rates of return will tend to exceed DCF rates of return. In the Foster Associates study cited previously, book rates of return exceeded DCF ates of return by 2.2 to 5.5 percentage points.) The implication is that the DCF rate f return required by the petroleum industry to be competitive in capital markets would e substantially *less* than those shown in the table.

	Return before taxes		Return after taxes		
	Income as percentage of stockholder equity (FTC mean)	Total return on total assets [a]	Income as percentage of stockholder equity: FTC mean	Income as percentage of stockholder equity: Fortune 500 median	Total return on total assets [b]
1966	22.4	7.5	13.4	12.7	5.5
1967	19.3	7.1	11.7	11.3	5.5
1968	20.8	7.5	12.0	11.7	5.5
1969	20.0	7.9	11.4	11.3	6.1
1970	15.6	7.6	9.3	9.5	6.1
1971	16.4	6.9	9.7	9.1	5.3
1972	18.4	7.7	10.6	10.3	5.4
1973	21.7	9.4	12.8	12.4	7.2
1974	[c] 24.7	11.4	[c] 15.5	13.6	9.2
Average [d]	19.8	8.1	11.8	11.3	6.2

[a] (Income after taxes—Fortune 500—times (income before taxes divided by income after taxes—FTC) plus (net indebtedness—Fortune 500 times the prime commercial rate)) divided by total assets - Fortune 500.

[b] (Income after taxes—plus (net indebtedness times the prime commercial rate)) divided by total assets—all from Fortune 500.

[c] 1st 3 quarters.

[d] From geometric mean of (1+r).

Even with this qualification, none of these rate of return measures is uniquely ap-ropriate to the kind of balance sheet anlaysis used by LaRue, Moore & Schafer. The nost nearly appropriate concept and the one most useful in evaluating the profitability f investments *within a firm* is probably total pretax returns against total assets, while he *outside investor* is interested in after tax returns to stockholder equity. The average 966–1974 figures for the two measures in U.S. manufacturing were 8.1 percent and 1.3–11.8 percent respectively (depending upon the source). LaRue, Moore & Schafer's standard of 15 percent, however, is for after tax total returns (profits *and* interest) gainst total assets. This figure in 1966–74 averaged only 6.2 percent for all U.S. manu-acturing. (Even this figure contains an upward bias, because we were not able to measure he cost of debt directly. Using the current prime rate as a proxy for the cost of bor-owed capital, as we did here, exaggerates this cost in a period of rising interest rates.)

This special profitability is necessary in the LaRue, Moore & Schaf view because (a) oil development is risky, (b) it is undertaken small producers, and (c) it is financed out of equity capital.

These characterizations, which apply to only part of the industr are not necessarily appropriate to a study purporting to cite avera costs for all oil discoveries in the U.S. (less Prudhoe Bay). Each them, moreover, is only partly true. Initial stages of oil explorati and development have traditionally depended upon a large number small "wildcat" operators. Much reserve activity is, now, howeve moving toward expensive sites off shore and in the Arctic, where major proportion of financing must come from major integrated petr leum corporations, though the efforts of independent drillers will st play a large part in the expansion of U.S. production.

Yet even in the past major firms, either through their own e ploratory efforts or by participating agreements with small operato have shouldered a substantial share of capital requirements for e ploration and development, and as reserves move towards the pe of their productive lives a far greater portion of the benefits and co of exploiting them shifts to integrated firms. The 15 percent after-t rate of return posited by LaRue, Moore & Schafer, when applied the complete amount and duration of investment in oil reserves, wou mean that these firms can also expect profitability rates far in exc of standards for the economy as a whole. Yet these firms, the major companies, are large and varied enough in their commitments that t risk premium necessary to attract capital to a small operation is hard a "minimum" requirement. It is not surprising, therefore, that t average after-tax earnings on investment by petroleum corporatio have tended to be almost the same as the average for all manufacturi industry.[5]

Fixing a particular rate of return has, in a discounted cash fl model, a decisive impact on its results. Had the 15 percent standa

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[5] ***Comparison of Rate of Return in Petroleum and Other Industries.*** The average aft tax rate of return on stockholders' equity of the "petroleum refining" sector of Fortune 500 (which contains the major integrated oil companies including their prod ing operations) was almost identical with that for the 500 as a whole (11.4 and 1 percent respectively). The following table shows the figures for indiviual years:

	Median rate of return on st holder's equity	
	Petroleum refining	manufactu
1965	10.4	[illegible]
1966	12.3	[illegible]
1967	11.2	[illegible]
1968	11.8	[illegible]
1969	10.5	[illegible]
1970	10.3	[illegible]
1971	9.0	[illegible]
1972	9.4	[illegible]
1973	13.4	[illegible]
1974	16.8	[illegible]
Average*	11.4	[illegible]

*From geometric mean of (1 + r).

NOTE.—The 1974 Fortune 500 contained 29 oil companies. According to the 1973 Annual Survey of Oil Gas (U.S. Department of Commerce, Bureau of the Census) the top 25 companies (in terms of oil and lease revenues) made 42 percent of the total U.S. expenditures on exploratory dry holes, 65 percent of to exploration expenditures, 62 percent of development expenditures, and produced 78 percent of the cr petroleum and condensate.

ən used as a pre-tax measure, or after tax earnings set at 10 percent oth assumptions are approximately equal, given the oil industry's x structure even after partial depletion repeal), the "economic prices" ojected would have been reduced 12 to 15 percent for various years; deed, by this one correction alone, the "economic price" would have ıyed below the actual oil price up to the mid-1960's.

Exclusion of the North Slope of Alaska

No economic rationale is advanced for excluding the reserves added the North Slope of Alaska. The current API figure for proved serves the Prudoe Bay field is confined to the biggest reservoir, Sadelrochit. It makes no allowance for future revisions or extenns, ignoring, for example, the billions of barrels of recoverable oil w known to exist in the Lisburne and Kuparuk formations, but is vertheless greater than the sum of *all* new reserves attributed by Rue, Moore & Schafer to the years between 1969 and 1974, inclusive. ius by one unexplained assumption, the report has reduced total serve additions in the United States by more than one half. While exploration and development expenses incurred on the North ope have apparently also been omitted, these were insignificant comred to the expenditures that *were* included from elsewhere in the nited States.

More important, perhaps, the oil and gas reserves contained in aska's North Slope are not only immense; they are fuel sources at the oil industry was anxious to tap long before the era of $10 per rrel crude oil, or the prospect of crude at $12 or more that Nathan w urges. This eagerness itself reveals something of the "economic ice" necessary for development in these regions, and it tells someng else too. For as the opportunities for profitable North Slope velopment were perceived, and as these opportunities were converted o corporate commitments, investment funds and interest were awn away from the traditional fields below the Arctic into field velopment and pipeline construction. Petroleum's financial prosets in Alaska are as relevant to "lower forty-eight" activity as are figures obtained by LaRue, Moore & Schafer for lower fortyht development itself.

The Prudhoe Bay discovery is indeed exceptional. We have no way knowing how many more "supergiant" oil fields—if any—will yet discovered in Alaska, or elsewhere in the United States or on its ter Continental Shelf. Yet Nathan makes much of the riskiness of exploration gamble—whose reward includes the hope of bonans just as its cost includes the chance of failure. Any assessment the expected responsiveness of oil supply to oil price—and any lgment what price is needed to elicit a given supply—must enmpass both ends of the probability spectrum. The exclusion of the askan experience, precisely because of its rich finds at relatively v unit costs, creates a decisive upward bias in the model's results. d it tokens, at the same time, extremely narrow approach to energy tters taken by its authors.

Depletion Allowance

Since preparation of the Nathan study, use of the depletion allowce has been substantially restricted. This change would, other things

being equal, require a higher selling price and a greater level of preta
earning to achieve any specificed rate of after-tax profitability. But th
one downward bias in the Nathan scheme is certainly dwarfed b
the many and substantial upward tilts contained in its methods. Th
estimates cited—for the effect of bonus inclusion, underestimation c
reserves, excessive rate of return—underscore this point all too clearl
for just a few of these biases.

CONCLUSION

The foregoing points have been addressed to those components c
the LaRue, Moore & Schafer analysis most critical in shaping Robe
R. Nathan's economic price conclusions. Invested capital to be reco
ered profitably, the revenues attributable to sale of oil, the volun
of crude oil on which costs and profits are to be made, and the ra
of return at which profitability should be set—each of these elemen
could under differing but reasonable assumptions result in an "ec
nomic price" estimate far closer to historical prices than to Nathan
conclusion. A complete assessment of their effect would require a vi
tual duplication of the LaRue, Moore & Schafer exercise with di
ferent and more appropriate assumptions.

THE USEFULNESS OF HISTORICAL COST ANALYSIS TO DETERMINE FUTU PRICES

There would seem little purpose in such duplication. For, even
all the inappropriate assumptions identified in this memorandum we
modified, we would have to question the whole logic of the LaRu
Moore & Schafer model and the use to which it has been put by M
Nathan. Over the long term, the rate of return on investments in cru
oil producing facilities is not determined by the price of crude o
Whatever is the price of oil, firms will invest in those prospects (a
only those prospects) which promise as good or better profits th
are available from alternative investment opportunities. Abnormal
high profits expected from exceptionally favorable prospects will te
to be appropriated by landowners (including the federal governmen
in the form of leasehold charges, so that oil producers will tend to
left with about the same average rate of return on their investme
as is experienced by other industries. The price of crude oil, ther
fore, determines not the rate of return but *the amount of exploratic
and ultimately of production that will take place in the course c
earning a return competitive with other kinds of business.*[6]

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[6] *"Costs" are Determined by Industry Expectations in Certain Models.* The Circul
logic of balance-sheet-type cost analyses like that of the NPC or LaRue, Moore & Schafe
has a curious implication: to the extent that such an analysis correctly specifies (1) t
timing and cost of past reserve additions (or the probability of future explorato
success) and (2) the expected rate of return necessary to justify investment, they w
produce an "economic price" just about equal to *the price industry expects to preva*
This is because the industry will undertake only those exploration ventures that lo
profitable at the expected price—and moreover, will bid up price-inelastic elements
costs (including lease bonuses and, recently, rig-time and certain drilling supplies)
a level that tends to absorb any expected "excess" profits above a competitive ra
of return.

Because of unforseeen developments (OPEC's price increases, changes in regulato
policies, etc., exceptional exploratory luck, etc.), price expectations and cost realiti
will diverge one direction or another in individual years. But on the whole, the cost
"economic price" projections of such analyses as the NPC or Nathan should tend to tra
industry price expectations rather closely. That fact that the Nathan analysis co
sistently results in "economic prices" higher than those that were anticipated by t
industry (as well as higher than current prices) actually indicates more about t
upward bias of the assumptions of the analysis than it does about the appropriatene
of the prices that actually prevailed.

Unless we know *how much* oil is likely to be discovered and ultimately recovered at each level of costs per barrel, and couple this schedule with a statement of how much crude oil we *want* (at any given price), we cannot meaningfully specify the necessary "economic price" for crude oil. Because the LaRue, Moore & Schafer model does not address itself to the relationship between the volume of oil that can be discovered and produced at different levels of cost, it would have nothing useful to say about the proper or desirable level of crude oil prices even if it were purged of its economic and accounting fallacies.

The Nathan testimony does not tell us how much domestic oil would be discovered and produced at $12.75 per barrel. Taken at face value, however, his analysis is terribly pessimistic. Cost outlays of almost thirteen dollars per barrel are credited with 1974 reserve additions which were far less than sufficient to maintain current production, much less to meet future growth or reduce imports.

Even if we had confidence that Nathan's 1974 "economic price" were accurate, and that the same outlays would produce the same results in 1975 as they did in 1974, we still would not know the proper price for crude oil. Thirteen dollars per barrel may be the "cost" of so many million barrels per day, but that may not be as much oil as we would like. But how much more oil would $15 or $30 per barrel elicit? We do know that still higher prices would have bid up the value of leases and factors of production whose supply is not readily increased. By doing so, higher oil prices would by themselves further increase the "economic price" as defined by Nathan. We also know that such prices would create immense windfalls for some producers and have serious inflationary and contractionary effects on the general economy. Unfortunately, however, we still cannot predict with much confidence the effect of higher prices on oil discoveries, and the Nathan analysis does not advance us along the path to such predictions.

It is very likely that $13 crude oil will *not* make the United States self-sufficient, or even 75 percent self-sufficient in petroleum by 1985. But how much *less* self-sufficient would we be if the price of "new" oil were reduced to $10, or $8, or even less? Again, the Nathan analysis is silent. It is not implausible that the loss of production would in fact be negligible compared to the benefits in reduced inflation and expanded economic activity.

Several earlier studies attempted to measure the historical responses of petroleum exploration and production to price fluctuations in the range between $1.50 to $4 per barrel which encompassed the prices that prevailed between World War II and the Arab embargo. These analyses cannot, however, easily be extrapolated to prices far outside of these limits. The responsiveness of oil production to price changes above (say) $6 per barrel may indeed be substantial, and it may not.

It is difficult to ignore the fact, however, that industry groups like the National Petroleum Council (NPC) and the Independent Petroleum Association of America (IPAA) were only two or three years ago telling us that $4 or $5 per barrel would result in an acceptable degree of self-sufficiency. What has really happened in the intervening period? Inflation alone could be expected to raise these figures by only 20 to 30 percent. Within the range of plausible prices (say $7 to $15), it is not clear whether discoveries are more sensitive to actual

prices themselves or to other variables such as OCS leasing policy the general economic and investment climate, sheer luck, or the sta bility of industry's expectations regarding prices, regulation an taxation.

Mr. Nathan in his Interior Committee testimony has argued tha crude oil prices prevailing from the early 1960's up to the cartel' price hikes were insufficient to signal private oil firms into the do mestic exploration and development activity necessary to maintai domestic reserves at the levels which we would have (retrospectively deemed desirable. While respectable opinion agrees on this point host of other factors influenced the evolution of the domestic oil sup ply situation during this period. For example:

Substantial oil industry exploration and development activit took place overseas with the aim of exploiting the lowest cos prospects. This activity received strong government encourage ment including but not limited to generous tax incentives. Th prospects developed were dominated by supergiant oil fields i foreign countries (where production costs were very low com pared to most U.S. fields), and this fact contributed greatly t increased American dependence on these sources of supply.

Leasing on the Outer Continental Shelf proceeded at a snail' pace both because of a desire on the part of the Federal Govern ment to maximize lease bonus revenue per acre and because o opposition from some coastal states and onshore produce interests.

State prorationing, assisted by the Mandatory Oil Import Pro gram, stabilized prices (albeit at levels above the then curren world market prices) and obscured the signals of declinin domestic oil availability until Texas and Louisiana fields reache nearly 100 percent of their effective producing capacity in 1972- 1973. The U.S. regulatory system left domestic producers, con sumers, and the government alike unaware of growing deficienc in domestic supply until it created spot shortages in 1973 an more importantly left the U.S. vulnerable as it had never bee before to the cutoff of Arab oil.

These observations tell us part of the story that led to the curren oil supply problems of the United States, but neither they nor the ac counting exercise carried out by LaRue, Moore & Schafer and in terpreted for us by Mr. Nathan, offer a concrete program for the future

We are left, that is, where we were before: with an understandin that elements in Federal energy policy—including prices, impor quotas, tax treatment, environmental regulation, and leasing proce dures—all contributed to the creation of our immediate oil problem but with no clear guide to the equitable and efficient correction of thes past mistakes.

TATEMENT OF ROBERT R. NATHAN IN RESPONSE TO THE SENATE INTERIOR COMMITEE STAFF ANALYSIS OF THE NATHAN NEW OIL PRICE STUDY, AUGUST 1975

VERNER, LIIPFERT, BERNHARD & MCPHERSON,
Washington, D.C., August 7, 1975.

Ir. WILLIAM VAN NESS,
'eneral Counsel, Senate Interior Committee,
Vashington, D.C.

DEAR BILL: Enclosed is a statement by Robert Nathan and John a Rue, responding to the Interior staff's criticism of the La Rue, Ioore and Schafer study and the Nathan testimony based thereon. Ve appreciate your offer to include this as part of the record.

Sincerely,

HARRY MCPHERSON,
Counsel for the Small Producers for Energy Independence.

Enclosure.

TATEMENT OF ROBERT R. NATHAN IN RESPONSE TO THE SENATE INTERIOR COMMITTEE STAFF ANALYSIS OF THE NATHAN NEW OIL PRICE STUDY

On July 16, 1975, Senator Henry M. Jackson placed into the 'ongressional Record a Senate Interior Committee staff analysis of iy testimony on oil prices and the study on which it was based, 'alculation of New Oil Costs, United States, Years 1959 Through 974, May 1, 1975, La Rue, Moore and Schafer.

There is set forth below a point by point response to the questions aised and the claims made in the staff report. Several general observa-ons would seem to be in order, however, before the more detailed nalysis is undertaken.

Both my testimony and the La Rue report examine the economic ɔst of finding and producing new oil only. In my testimony, I made clear that if the economic cost of new oil is significantly more than ie price, there will be less and less exploration and that additions to ɜverses and domestic production will be at lower levels. This can only iean increased imports.

For this reason, in pointing out all the things the La Rue study did ot do (e.g., sensitivity analyses, omission of old oil, released oil and ripper well oil, secondary and tertiary recovery, etc.) the staff report 'iticizes the La Rue study for not including analyses which are not ermane to the object of the study, which was to calculate the economic ɔst of new oil. This scarcely constitutes a sound basis for criticism.

In comparing the La Rue study results with those from other ɔurces, the staff report is exceedingly careless. While differences in iemselves do not necessarily lead to the conclusion that the La Rue udy, or any other study, is therefore incorrect, the differences should

be real and not contrived. Thus, comparison is made with cost data in other studies which include old oil. Citations from other studies are highly selective and do not always represent the main thrust of the study conclusions. Comparison is made with studies using a different time frame or a different set of assumptions.

Finally, the staff report is critical of the La Rue study because it is "totally unable to relate a particular crude oil price to the level of production which would be forthcoming at that price." While such information would indeed be valuable, it does not exist today, nor is it likely to exist in the immediate future.

I put the matter succinctly and clearly in my testimony before the Senate Committee on Finance on July 10, 1975. I said:

"If Senator Nelson or Senator Long had said to me, 'Mr. Nathan if you let new oil prices go to $12.83 are you confident you are going to get a tremendous amount?' And I would say no. 'I do not know. All I am saying is that if you do not let it go near the cost, you are never going to know because you will not get the drilling.' "

Following is a point-by-point reponse to the Interior Committee staff analysis:

1. Interior Staff claim:

Oil cost calculation by LaRue, Moore & Schafer "far exceeds" those calculated by the National Petroleum Council and Federal Energy Administration Project Independence.

Nathan-LaRue response:

a. The only oil costs ever calculated by the National Petroleum Council were for new oil plus old oil, which may have been discovered in prior decades and cannot be related in any way to the cost of new oil.

b. Project Independence supports the LaRue, Moore & Schafer analysis. Oil costs based on 1973 drilling costs, when calculated using 15 percent rate of return and including lease bonuses, were:

	Per barrel
West Texas, New Mexico	$11.6[illegible]
Texas, Louisiana Gulf Coast	9.0[illegible]
Texas, Louisiana offshore	11.2[illegible]

c. Other sources cited by the Interior staff do not back up its claims. To wit: The MIT study (May, 1974) says, "The results indicate that prices of $11 to $13 per barrel (oil equivalent) will be necessary to bring forth enough additional supplies of fossil fuels to satisfy demands in domestic energy markets at that time." To this is added in a footnote, "The prices are for 1973 and a factor of 10 to 15 percent must be applied to convert to 1974." The 1974 price, according to this source, should then be between $12 and $15 per barrel.

A Foster Associates study is quoted as saying that finding and other direct costs average $1.85 to $2.20 per barrel based on 1957–1967 data. LaRue, Moore & Schafer costs comparably computed were $1.87/barrel for the same period. The Interior staff fails to mention further statements that appear in the Foster Associates Study, namely, "Thus the results of this study are a more nearly accurate reflection of the present cost of finding hydrocarbons discovered in the past five to ten years than they are a forecast of the cost of finding new supplies in the next five years." The Foster report further states, "The results of this study are, therefore, not a measure of the economic cost of finding

new supplies in the sense of measuring total costs, including an allowance for return commensurate with risk, but instead are measures of comparative profitability at present price levels."

2. Interior Staff claim:

Dollar outlays have been "consistently overestimated" by assuming an after tax rate of return "two and one-half times" greater than that of U.S. manufacturing and "ignoring enormous low cost reserves discovered in Alaska."

Nathan-LaRue response:

a. The staff attempts to make a meaningless comparison between "total return on total assets" after taxes (which is said to be 6.2 percent for all U.S. manufacturing) and a 15 percent, after tax, discounted cash flow rate of return on new projects. The folowing example illustrates the fallacy inherent in such a comparison. From the LaRue, Moore & Schafer projections, capital expenditures associated with new reserves added in 1973 were $2,846 million. If the after tax rate of return were 15 percent, these capital expenditures would produce an after tax profit of $2,434 million over a 26-year period. The "total rate of return on total assets" after taxes would be 6.5 percent per year (see page 12).

b. The reserves discovered in Alaska (i.e., Prudhoe Bay) have nothing whatever to do with economic costs in other areas of the United States which to date have produced 100 percent of the nation's oil. The Prudhoe Bay field is expected to produce 1.6 million barrels a day, or about 10 percent of the nation's petroleum requirements. Even if Prudhoe Bay had been included along with the remainder of the United States, economic oil costs would be charged for the year in which the reserves were booked. There is a common misconception that Alaska oil is cheap oil. Nothing could be further from the truth. Development of Alaskan fields will be far more expensive than comparable fields in other areas, and the chance of finding another field the quality of Prudhoe Bay is extremely small.

c. Sources are embraced in one claim and discarded in the next. For example, both NPC and Foster Associates excluded Prudhoe Bay in their economic studies, although both knew of the discovery.

A study, dated May 12, 1975, by the reputable Houston firm Butler, Miller & Lents concludes that the 1973 cost of new oil, exclusive of profits, was $9.83 per barrel. This study was selectively ignored in the Interior staff's analysis.

3. Interior Staff claim:

"The LaRue, Moore & Schafer study only addresses the question of newly discovered oil." It provides no standard for pricing old oil, released oil, or stripper oil. It does not even claim to provide a guide to prices required for secondary and tertiary recovery.

Nathan-LaRue response:

a. The LaRue, Moore & Schafer study is exactly what it is purported to be— a study of the economic cost of each year's new oil supplies. It has nothing whatever to do with old oil, stripper oil, and released oil, which are all constructs of government policy. Costs of new oil are indicative of replacement costs of existing reserves; without replacement, existing reserves are in liquidation.

b. Secondary reserves and related costs attributable to newly discovered oil are taken into account in yearly projections. Because of the

high costs involved, there will be no significant tertiary recovery at old oil prices.

4. Interior Staff claim:

The study, if carried to its conclusion, would suggest that a Federal Power Commission type cost-based formula should be adopted for oil pricing.

Nathan-LaRue response:

The study was carried to its conclusion, which was that oil costs more to find and develop than at any prior time in our history, and that the petroleum exploratory effort will decline if the selling price of oil is below its economic cost, as defined by the 15 percent rate of return. By no stretch of the imagination can it be said that the study suggests that a cost-based formula for oil pricing is needed, desirable, or workable.

5. Interior Staff claim:

The LaRue, Moore & Schafer study does not "relate a particular crude oil price to the level of production forthcoming at that price."

Nathan-LaRue response:

a. The pupose of the study was to examine the historical trend in the economic cost of new oil between 1959 and 1974. Further, a comparison was made between the economic cost of oil and its selling price, and the disparity between the two was correlated with the level of petroleum exploration activity. The relationship between the volume of oil that can be discovered as a function of its cost cannot be calculated with any degree of certainty for a very simple reason: no one knows what is underground without drilling a hole. For example, Exxon and its partners would hardly have spent $650 million in the last two years offshore Florida had they known that their lease was worthless. The Navy would not have bothered to drill its $7 million North Slope well on the Naval Petroleum Reserve had they expected a dry hole. While the absolute volume of oil cannot be estimated as a function of price, reliable qualitative relationships can be easily seen.

When the economic cost of oil exceeds its selling price, exploratory drilling for oil will decline and ultimately cease. The LaRue, Moore & Schafer study makes abundantly clear that just such a decline occurred between 1964 and 1973 when industry rates of return fell below 15 percent. During this period, oil well drilling fell 55 percent, although it was a period of rising petroleum demand. An increase in activity, the first in 10 years, occurred in 1974 only when economic prices moved up to approach economic costs. Now that new oil costs have been increased by about $1.90 per barrel (because of repeal of the depletion allowance), oil exploration programs have again been cut.

Regardless of new oil price, the United States will find it extremely difficult to become self-sufficient in crude oil. The nation can, however, maintain its present degree of independence in oil supplies if the price for new oil offers an incentive for exploration. To set arbitrary new crude oil prices at a level which will provide less than the maximum exploratory effort otherwise attainable is sheer folly.

It should be apparent to all that any barrel of oil we do not find because of artificially restricted petroleum exploration must be purchased at higher cost from OPEC. The economically "ruinous" prices, which should concern the Interior staff, are flat prices which discourage to any extent exploration activity which would normally occur in the absence of controlled prices.

(NOTE.—The following is a more technical discussion of "principle conclusion" reached by the Interior staff after "careful study." These "conclusions" are in reality a collection of assertions based on incorrect intetrpretation or irrelevant conjecture.)

COMMENTS ON PRINCIPAL CONCLUSIONS OF SENATOR JACKSON'S STATEMENT

When the staff complains that the method used in the LaRue, Moore & Schafer analysis is "comparable to those used by corporate planners in assessing the likely profitability of potential investment", and suggests that oil "reserves developed in earlier and less expensive periods" should be included in these calculations, it demonstrates a profound misunderstanding of the forces that drive petroleum exploratory activity. Every manager is obligated to invest his firm's capital in ventures which produce a rate of return sufficient to perpetuate the existence of the firm. The fact that an oil company may have certain reserves which it can produce at $1.00 per barrel has nothing whatever to do with its future petroleum exploration ventures.

The exploration manager's judgments are necessarily based on the extrapolations of his past experience, and trends established in the last ten years show conclusively that oil has become more expensive to find and produce. If pro forma economics of new drilling ventures show that the economic cost of new reserves added is likely to exceed their selling price, then exploration activity will decline and the funds originally slated for exploration ventures will go to other projects, some of which may be outside of the energy industries. The search for new oil may be financed by the profits from old reserves; however, it is absurd to think that profits from old oil will subsidize the production of new oil for any length of time, and that producers will risk money searching for oil which must be sold at prices less than its economic cost, even though overall company operations may be profitable.

Leasehold costs are regarded by the Interior staff as "transfer payments—unnecessary as a cost either to society or to the producers who make them." They further suggest that the fact the lease were acquired at all is proof that the producers anticipated that prices would be sufficient to support exploration, development, and producing costs. Apparently, the justification for these statements is that oil price determines the amount which a producer can bid for a lease. While this argument appeals to many theoretical economists, it has no place in the real world, and in particular, it cannot apply to historical studies where oil prices have been constant.

Leasehold costs are incurred at the very front end of an exploratory program. To afford protection, an operator must acquire more exploratory rights through the acquisition of leases than he will ultimate use, and most of the leases will be worthless. Typically, onshore leases are negotiated with landowners who set their asking price arbitrarily, and will not accept less. The offshore leases in Federal waters are sold by sealed bid, and the government of the United States has the right to reject any and all bids. The value of the leases prior to their drilling is extremely difficult to determine, and is subject to wide variation of opinion, as demonstrated by the spread of bids on any offering of offshore Federal leases. While the average of all bids may be more nearly the correct value, the lease is not sold at the average price,

but to the top bidder, and frequently the top bidder pays too much. Moreover, many reasonable bids are rejected by the Federal agency. The leases may be worthless, such as the $632.4 million block of acreage in the Destin anticilne offshore Florida, but producers who participated in the Destin venture can hardly be called foolish, because the quality of the geologic prospect was such that it could have added materially to the nation's reserves. Since the oil companies did not get their money back from the government after the leases were proved worthless, these leases and others must be paid for by the companies themselves, and the costs to the producers are just as real as those paid to drilling contractors. Further, these costs can only be charged to the cost of new oil, because they were incurred in the search for new production and have nothing whatever to do with older reserves.

To say that lease bonuses paid are anticipatory of increased oil prices is unrealistic. Lease costs included in the LaRue, Moore & Schafer projections for the year 1974 were actually those expended in the year 1972. Lease costs included in 1973 projections were actually those incurred in 1971. This two-year shift was made in order to place lease and drilling costs more nearly in the year in which the leases were actually drilled. To say that operators in 1972, after more than 17 years of constant oil prices (decreasing prices in real terms), expected oil prices to rise suddenly to over $10 per barrel in 1974 and calculated lease bids accordingly, stretches the imagination. It should be noted that oil costs increased only after the major oil companies lost control of the "cheap foreign oil" from OPEC countries. The payments for lease bonuses were developed over a period of near-contant oil prices, and the lease bonuses were justified based on those prices in anticipation of greater revenues. What the Interior staff chooses to ignore is that during the period between 1964 and 1974, drilling of oil wells dropped over 50 percent, and the exploration industry was in the process of liquidation. Had this trend continued, drilling for oil would have ceased in the early 1980's.

TREATMENT OF NATURAL GAS

The Interior staff alleges, without stating its authority, that the average price of natural gas in intrastate sales in 1974 was already over $1.00 per Mcf, implying that the coproduct credit for natural gas as applied in oil should be at least $1.00. Factors the staff fails to take into consideration are that many of the new oil discoveries are in oil areas where only interstate markets exist. Gas, unlike oil, is commonly sold on long-term contracts, and much of the gas and oil produced in the areas is already dedicated under old contracts. Further, the staff fails to note that natural gas produced from oil wells does not have the same value as gas produced from gas wells. Oil wells typically produce small quantities of gas at low pressure, requiring expensive gathering, compression, and treatment before it can be sold. A portion of the gas is used for lease fuel and is therefore not available for sale. The 44.9 cents selling price for new oil well gas used in the LaRue, Moore & Schafer study is probably on the high side of prices actually received by producers in 1974. But even if the price were doubled, the economic cost of new oil would be reduced by only 5 percent.

Another erroneous allegation is that costs attributed to exploration or new oil were responsible for discovery of non-associated gas reserves. Exploratory wells being drilled for oil production occasionally nd non-associated gas reserves. Similarly, exploratory wells being rilled for natural gas occasionally discover new oil deposits. The oint Association Survey compiles and reports the cost of wells by ategory, oil wells, gas wells, and dry holes, as well as the number of oles drilled in each category. These data provide a definitive basis for llocating exploration costs between oil and gas ventures. Operating osts are allocated to oil and gas wells on the basis of the number of vells contemplated in each category. Since gas wells cost less to operate han oil wells, this procedure tends to allocate too little cost to producng oil wells, and therefore tends to make the calculated economic ost of new oil too low, which is just the opposite of the interior staffs' laim.

USE OF RESERVE FIGURES

The complaint made that gross reserves additions in the LaRue, Moore & Schafer projections do not include the full amount of API evisions in each year. This statement demonstrates a total lack of nderstanding of what reserve revisions are.

Revisions to oil reserves have generally been due to changes in reerve estimates for older giant fields found in the 1920's and 1930's. These changes in estimates come about through improved technology or estimating reserves which were not available at the time of disovery, and through the installation of large secondary recovery projcts. Of the annual reserve adjustments made since 1967, more than 70 percent of the total was applicable only to fields discovered more han ten years before the date of adjustment, and more than 50 perent of all adjustments made since 1967 apply to fields discovered prior to 1941. These revisions, for the most part, apply to old fields nd have little or no bearing on the quantity of new oil discovered hrough drilling.

While the LaRue, Moore & Schafer study uses a constant reserve ppreciation factor of .75, there is persuasive evidence that the factor nay be decreasing and the estimates of reserves are overstated for ecent years, which is just the opposite effect of that claimed in the Interior staff's statement. Improved well logging and geographical ools enable reserves to be defined early, as evidenced by a pronounced lecline in extensions to old fields beginning in 1956. Moreover, since he mid-1960's, it has become a much more common practice to maxinize ultimate oil recovery by installing pressure maintenance equipnent early in the life of the field, thereby skipping the "secondary phase" and adding reserves initally, which in earlier periods would have been added through revisons many years later. The revision facor used in these studies does take into account future secondary reerves and their capital requirements, and the costs of installing the econdary processes are delayed until five years after the field's development. Contrary to the claim made in the Interior staff statement, he treatment of revisons used in the LaRue, Moore & Schafer study ends to produce reserve estimates which are too high, and if anyhing would cause the economic oil cost to be understated.

CRITIQUE OF API RESERVES

Another assertion expressed in the Interior staff's statement is that API reserve figures "have not been adjusted to take into account higher price levels." The LaRue, Moore & Schafer study investigated all pertinent and available historical data on an annual basis. Data on reserves added by drilling plus allocated revisions during a given year, the expenditures for that year, and the tax structure in effect for the given year were all used to arrive at an economic price per barrel required to yield a 15 percent rate of return. Thus, reserves added in a given year did incorporate the economic cost and conditions prevailing for that year. Future speculative reserve adjustments due to price increases or decreases were not considered predictable and did not alter investment decisions during that given year. In 1974 when oil prices were higher, the reserves added by drilling were calculated by API with the full knowledge of the prevaling price structure. Thus reserves added by drilling during 1974 did incorporate the prevailing ecoonmic conditions and these reserve data are included in the report.

THE RATE OF RETURN

In its statement the Interior staff submits that "total return on total assets" for all U.S. manufacturing industry during the period between 1966 and 1974 averaged 6.2 percent. Further, the staff claims that this 6.2 percent is numerically comparable to the 15 percent discounted cash flow rate of return used to arrive at economic cost in the LaRue, Moore & Schafer study. The technique used by the staff in arriving at the 6.2 percent was to take from the Fortune 500 group after tax income, add net indebtedness times prime commercial rate, and divide this by total assets. No rationale is given of why this number even remotely resembles a discounted cash flow rate of return. However, the same type of number can be calcuated for each year of the LaRue, Moore & Schafer projections, all of which contain prices necessary to give a 15 percent discounted cash flow rate of return. A comparison of these numbers is as follows:

	Total return on total assets	LaRue, Moore & Schafer rate calculated on same basis (a)
1966	5.5	6.4
1967	5.5	6.2
1968	5.5	6.2
1969	6.1	6.5
1970	6.1	6.8
1971	5.3	6.7
1972	5.4	6.5
1973	7.2	6.5
1974	9.2	6.6
Total	6.2	6.5

Sample calculation: Year 1974, dollars in millions: Assets over reserve life: $4,632+0÷2=$2,316. Annual income after taxes: $4,241/27.58 yr=$153.8. Total return on total assets: $153.8÷$2,316 *100=6.6 percent.

It may be seen that the total rate of return on total assets as defined by the Interior staff is 6.2 percent for the period between 1966 and 1974 inclusive. The average for the LaRue, Moore & Schafer data when

calculated on the same basis for new projects yields 6.5 percent. A comparison of these two numbers, 6.2 percent versus 6.5 percent, hardly substantiates the staff's claim that one exceeds the other by a factor of "two and one-half."

The Foster Associates study using 1967 and earlier data puts the estimated return on book capital in better perspective. According to the Foster study [1] the estimated return on book capital for oil reservoirs was 7.2 to 8 percent in the Gulf of Mexico, 11.9 percent on onshore South Louisiana, and 7.2 percent in other continental United States. The author further states that "the overall rate of profitability of current outlays for finding and producing hydrocarbons is less than the returns on capital experienced in earlier years and also lies below the approximately 13 to 15 percent rate of return currently earned on book capital by a large segment of U.S. manufacturing enterprises." [2] The discounted cash flow, according to Foster, for oil reservoirs in the Gulf of Mexico during the same period was estimated to be from 5.0 to 5.4 percent, onshore South Louisiana 6.4 percent, and other continental U.S. 4.3 percent. In comparison, the discounted cash flow rate of return for the five year period ending in 1968 from the LaRue, Moore & Schafer projections averages 6.6 percent which is in substantial agreement with the Foster estimates. Moreover, the slightly higher value calculated by the LaRue, Moore & Schafer model shows that economic oil cost calculated by that model would be somewhat lower than those which would be calculated by the Foster and Associates model. An inescapable fact was that the rates of return in this period were not sufficient to encourage sustained exploratory activity, and during the five year period 1964 through 1968, drilling for oil declined by one-third.

EXCLUSION OF THE NORTH SLOPE OF ALASKA

The North Slope of Alaska and its reserves have nothing whatever to do with the historical economic cost of crude petroleum in the remainder of the producing areas in the United States which have yielded 100 percent of the nation's production to date. If the reserves in the Prudhoe Bay field should indeed prove less costly than those from the remainder of the nation, this still has no bearing on what future economic cost will be in the Gulf of Mexico, Louisiana, or Texas, or California or any other of the more mature producing areas. It is exceedingly naive to assume that Alaska oil will be cheap, and there will be no need for additional exploration in the traditional producing areas because all future needs will be met by Alaska. The addition of the Prudhoe Bay reserves were of great significance to three major domestic oil companies, and do not in the least affect the remainder of the nation's producers, particularly the independents. Even the three major U.S. producers that share the Prudhoe Bay reserves are faced with the same costs in the remainder of the country as all of their competitors. The suggestion that funds were drawn away from the lower 48 states by the lure of Alaska between 1968 and 1973

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[1] Foster & Associates, "The Role of Petroleum and Natural Gas From the Outer Continental Shelf." U.S. Gov't Printing Office 1970, page 161.
[2] Ibid, p. 161.

makes little sense in light of the drilling and exploratory activity in Alaska during those years.

DEPLETION ALLOWANCE

The Interior staff attempts to brush away as insignificant the loss of depletion allowance to the nation's major producers. Eliminating the depletion allowance for 1974 would have increased the economic oil cost by $1.90 per barrel, an amount which is hardly insignificant. The importance of this loss to the petroleum industry is emphatically demonstrated by the cuts in exploration programs and budgets made by major producers following the repeal of the depletion allowance. Stated another way, loss of the depletion allowance has again pushed the economic cost of new oil to a level above its selling price and exploration activity, as a consequence, has begun to decline from what it would have been had depletion allowance remained at the 1974 level.

CONCLUSION

The Interior staff judges, apparently more from intuition than facts, that the economic cost of oil was really lower than that testified to by Robert Nathan. To arrive at such a conclusion one must ignore the activity levels in United States exploration which began to decline when the discounted rate of return, as defined by Mr. LaRue, Moore & Schafer, dropped below 15 percent and which was reversed only after the oil price increased above the economic cost. The facts lead to only one possible conclusion: that is, that any barrel of oil we fail to produce by virtue of reduced exploratory levels brought about by reducing new oil prices to levels below OPEC prices must in the foreseeable future be replaced by OPEC oil at a greater price. To say that we do not need new domestic supplies which cost more than $8.00 or $10.00 per barrel, and then to turn around and buy $13.00 oil from Arab countries to make up the difference, flies in the face of all reason.

The staff claims that the U.S. regulatory system left domestic producers, consumers, and the Government alike unaware of growing deficiency in dometstic supply until it created spot shortages in 1973. This simply is not so. Repeated warnings issued by industry spokesmen and private research groups were drowned out by voices calling for more cheap foreign oil. Now these same voices call for more cheap domestic oil. There is no more cheap domestic oil, and had there not been a substantial price increase, within 20 years there would have been no domestic petroleum exploration industry.

INTERIOR COMMITTEE STAFF RESPONSE TO COMMENTS OF ROBERT NATHAN AND JOHN LaRUE

The best rebuttal to the response of Robert Nathan and John LaRue to the Committee staff's critique of their testimony and analysis is a careful rereading of that critique. Many of the arguments made by Nathan and LaRue in their response were actually dealt with in the Committee staff's review of the original Nathan-LaRue presentation. The Nathan-LaRue response in many places simply acknowledges the restrictive assumptions of their orginal testimony and analysis. Committee staff had emphasized that these restrictive assumptions were critical in limiting the usefulness of the Nathan-LaRue approach as a guide to national oil price policy. In other places the Nathan-LaRue reply is, in our opinion, simply wrong, insisting upon reasoning that fails to respond at all to the Committee Staff criticism, or to take account of the economics of the petroleum industry or elementary accounting principles.

Leaving aside the more arcane issues of interest only to specialists and assuming for the moment that their "economic price" calculations are technically correct, the Nathan-LaRue presentations still provide no guide as to what the price of crude oil ought to be. LaRue, Moore and Schafer purported to find, for oil reservoirs discovered in each year from 1958 to 1974, the crude oil price which would provide a 15 percent after-tax return on the total investment committed to finding and developing those reservoirs. This return is achieved in the Nathan-LaRue model, however, *only on the assumption that the calculated price for each year prevails for the entire productive life of the reservoirs found in that year.*

Only a pricing system that provides different prices for oil reflecting the "vintage" of discovery is clearly consistent with the logic of the Nathan-LaRue argument. Such a system would provide several "tiers" of petroluem prices. With an "economic price" that rises from $2.86 per barrel for oil found in 1958 to $12.84 for oil found in 1974, what other pricing scheme could possibly meet the LaRue-Nathan rate of return criterion for every year's discoveries? The LaRue-Nathan response seems to imply that *all* crude oil, regardless of when it was discovered, should command in each year that year's "economic price" for new oil. If prices really behaved this way, however, producers would consistently earn truly awesome rates of return, far in excess of the already exceptional 15 percent on total investment assumed in LaRue's analysis.

The main issue in the present debate over oil pricing policy is whether the production from oil reserves developed before 1973 in anticipation of prices in the $3 to $4 range should be priced—

(1) at approximately their *historical costs*, including a "fair" return to producers

(2) at approximately their projected replacement costs; or

(3) at the current world market price (which may or may not approximate the replacement costs of domestic energy), or even higher.

This choice involves tradeoffs among equity between producers and consumers, the stability of the general price level and the general health of the economy, efficient resource allocation, equity among classes of consumers, energy conservation and energy self-sufficiency. The correct policy is not immediately obvious, and there are respectable lines of analysis and argument supporting each of the three broad principles of oil pricing policy. But as the Committee Staff critique pointed out and as Nathan and LaRue acknowledged in their response, they have not addressed this central issue.

Nathan and LaRue admit that presentations do not provide any support for a policy of decontrolling the price of *old oil* (or, for that matter, for continuing controls). They are also frank to stipulate that they have not even tried to estimate how much *new oil* would in fact be discovered and produced if its current price were about equal to the estimated "economic price"—a situation that seems to prevail right now. It is clear, therefore, that the LaRue, Moore & Schafer exercise is essentially irrelevant to debate now being carried on over crude oil price policy.

However, although the specific policy inferences of the Nathan and LaRue presentations are impossible to pin down, their broad thrust is unmistakable: they seek to create a climate favorable to higher oil prices, regardless whether the oil is "new", "old" or whatever. This, of course, is the understandable hope of Mr. Nathan's clients, the "Small Producers for Energy Independence", and this is the reason they commissioned the study. It is this thrust and this purpose which required us to comment upon the upward biases in the study's methods and assumptions, despite the Committee Staff's conviction that correction of these biases would still leave us without a correct price or a correct price policy.

These comments will touch briefly here on only two of the most crucial points on which Nathan and LaRue have defended their analysis—the treatment of lease acquistion costs, and the choice of a discount rate—and suggest again that the reader return to our original critique to judge the correctness and weight of their other defenses.

Lease acquisition costs. Nathan and LaRue simply restate the original rationale for including all lease acquisition costs as part of the industry's economic cost for crude oil. It is true, as they maintain, that each individual producer faces these charges as given, indispenable costs of exploration. But the amount he must offer to governments, Federal or State, or to private landholders for the rights to drill is determined by the competition for the tract in question. That competition is in turn determined on the one hand by the attractiveness of each tract and on the other *by the expected price of crude oil.* In other words, higher oil prices mean that companies as a group will, and as individuals must, bid more for leasehold rights.

In a competitive market for lease acreage—and all evidence points to a conclusion that this market is indeed workably competitive—producers will offer lease payments equal to the discounted value of the difference between all other costs (including the necessary return to capital) and their expected revenues from the sale of oil and

gas. The implication of this fact is that *the LaRue, Moore & Schafer approach is completely circular.* If all the other variables are specified correctly, their approach will *always* tend to produce estimates of an "economic price"—including bonuses and other leasehold costs—that are just about equal to the prices industry expects to prevail over the economic life of new discoveries.[1]

To state the preceding point a bit differently, competition will always tend to bid up the price of leases to the level at which costs equal expected revenues. The logic of the LaRue approach would, coincidentally, generate an "economic price" for Persian Gulf crude oil just about equal to the OPEC price. But that exercise would be no more and no less useful as an indication of the appropriateness of the OPEC price than the Nathan-LaRue exercise is for determining what the real costs are for new oil in the United States.

The rate of return. Nathan and LaRue do not really try to defend their choice of a 15 percent after-tax rate of return on total investment as a representative measure of the profitability of investment in the United States economy. They offer no response to Committee Staff's comment that 15 percent after taxes is a common—and probably appropriate—standard for judging individual prospective investments, but that no industry realistically hopes to achieve such a return on the whole of its assets.

Statistics are not available on the discounted cash flow (DCF) rates of return earned on new investment in different industries, and there would be serious conceptual and data problems in producing such statistics. In the years since financial statistics have been assembled, however, few industries have ever achieved a rate of return as high as 15 percent on total book capital. As Committee Staff pointed out in its critique, the average figure for all manufacturing industry over the years 1966 to 1974 was about 6 percent.

It was also observed, however, book rates of return would tend to exceed DCF rates of return in periods of rapidly rising prices (because of the undervaluation of capital consumption allowances and of the costs of replacing inventories). Indeed the Foster Associates study of 1967, to which Nathan and LaRue refer in their response to Committee Staff, states (p. 161) that "with few exceptions the DCF technique will show lower measures of return than the more traditional financial accounting measures." Staff reasoned, therefore,

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[1] It would be correct in certain other kinds of models for estimating *marginal* (as opposed to *average*) crude oil production costs, to include lease acquisition charges as part of these costs, according to the following logic: The marginal producing property or exploration prospect is one on which expected costs and revenues (either in total or per barrel) are just equal. The asset value of such a property or prospect is essentially zero, and no operator or explorer will pay any lease acquisition charge for it. On the other hand, any supramarginal property or prospect; (one where costs, including a competitive return to capital, are expected to be *less* than revenues) will have a positive asset value, and some operator or explorer will be willing to pay a price up to or equal to that value in order to obtain a lease.

Within this frame of reference, the expected marginal cost, that is, the cost of oil from the marginal property or prospect, is just equal to its expected price (both discounted to the present). For each supramarginal property or prospect, therefore, the expected cost of production (discounted to the present) *plus* its present asset value (=potential lease acquisition charges) equals the expected oil price (discounted to the present), which in turn equals the whole industry's marginal cost. By aggregation, then, the sum of all costs other than lease acquisition charges, plus the sum of all lease acquisition charges, divided by total production (all discounted to the same point in time) is equal to marginal cost. While this approach, which is *not* used by LaAue, *et al.*, as a bass for including lease acquisition charges in economic costs, would be vald accounting and economic framework for analysis, it would still provide no way out of the circularity of their logic.

that the discount rate used by LaRue, Moore & Schafer was one which would, if achieved as a DCF rate of return, make the oil industry far more profitable in real terms than the industries with which it has to compete for investment capital. LaRue and Nathan respond only with the very point Committee Staff made—that DCF and book rates of return are not the same thing, and imply that they are not even remotely related.

To make this last point LaRue and Nathan resort to a bizarre calculation—which makes no adjustment of total investment for depreciation or depletition, nor any allowance for the tax deductibility of interest expense—purportedly showing that their model produces a total return to book capital invested in 1974 reserves of 6.5 percent, a result not markedly different from the comparable figure for all U.S. manufacturing. A correct calculation of books returns from their table results in strikingly different figures.

Rearranging the data in LaRue, Moore & Schafer's cash flow table for 1974 discoveries into the format of a conventional income statement produces an average return on total book investment of 13.9 percent over the first 10 years of production. Assuming that 45 percent of invested capital was borrowed (the average 1974 figure for the oil companies in the Fortune 500 was 49.8 percent) at an average rate of 9 percent, the book return on stockholders' equity over the first 10 years of production would have been 17.8 percent. In view of the fact that these earnings figures are predicated on constant prices (and thereby represent a real as opposed to a nominal rate of return), $12.84 per barrel for new oil would seem to offer an exceedingly attractive investment prospect.[2]

No one, to our knowledge, has claimed to know what oil prices would have been just sufficient over the past decade or two to bring forth the amount of domestic exploration investment that retrospectively seems to have been desirable. This question may be fundamentally unanswerable, and conditions have changed so much in the last two years that the answer might be of little value if it were known. The amount of future exploration effort and discovery that would be brought forth by alternative oil prices is, however, an issue of the greatest importance, for which even a broadly approximate answer would be useful. It would be pleasing to be able to state that the labors of Nathan and the LaRue group have resulted in progress along the path to such an answer. Unfortunately we cannot honestly make such a statement.

[2] See the appended tables 1 and 2. Table 1 computes the book rate of return to stockholders equity and the total return (net income after taxes plus interest expense) on total book capital for 1974 reserve additions, directly from LaRue, Moore & Schafer's tables. Table 2 assumes that oil and gas prices, operating costs and the costs of new investment (in secondary recovery) all advance at 7 percent per year, and that no percentage depletion is allowed in computation of federal income taxes. In both cases, debt is 45 percent of total investment, and interest cost averages 9 percent. The inflation assumption increases book rates of return considerably, even without the depletion allowance. Table 2 gives a book rate of return on equity of 24 percent on stockholders' equity and 17.6 percent on total assets over the first ten years of production.

APPENDIX: CALCULATION OF BOOK RATES OR RETURN FROM LARUE, MOORE AND SCHAFER 1974 CASH FLOW TABLE

TABLE 1.—BOOK RETURN ON INVESTMENT IN OIL RESERVES ADDED IN 1974

[Dollar amounts in millions]

Year	Total invested capital (1)	Depreciation and cost depletion (2)	Total assets (adjusted basis) year end (3)	Stockholders equity year end (4)	Adjusted gross income (5)	Interest expense (6)	Federal income taxes (7)	Net income after taxes (8)	Net income after taxes plus interest (9)	After-tax return on stockholders equity (percent) (10)	After-tax return on total capital (percent) (11)
1974	$4, 491	$168	$4, 323	$2, 378	$414	$175	−$1, 229	$1, 300	$1, 425	34. 1	54. 7
1975		314	4, 009	2, 205	828	162	134	278	380	9. 4	9. 8
1976		291	3, 718	2, 045	828	151	206	180	331	8. 9	8. 8
1977		268	3, 450	1, 898	828	140	212	208	348	10. 1	11. 0
1978		258	3, 192	1, 756	828	129	218	223	352	11. 0	12. 7
1979	141	237	3, 096	1, 703	828	125	162	304	429	13. 8	17. 9
1980		225	2, 871	1, 579	828	116	222	265	381	13. 3	16. 7
1981		209	2, 662	1, 464	815	108	221	277	385	14. 4	18. 9
1982		194	2, 468	1, 351	726	100	194	238	338	13. 7	17. 6
1983		179	2, 289	1, 259	635	93	166	197	290	12. 7	15. 6
Average return (from geometric mean of 1 + R)										17. 8	13. 9

NOTES

(1) LaRue, Moore and Schafer, table 26, col. 8.
(2) Depreciation and cost depletion calculated by double declining balance method, 27.58 years economic life.
(3) (1), adjusted by (2).
(4) 55 percent of (3).
(5) LaRue, Moore and Schafer, table 26, col. 7.
(6) 9 percent of 45 percent of (3).
(7) LaRue, Moore and Schafer, table 26, col. 14, less 50 percent of (6).
(8) (5) − (2) − (6) − (7).
(9) (8) + (6).
(10) (8) / (4).
(11) (9) / (3).

TABLE 2.—BOOK RESERVES ON INVESTMENT IN OIL RESERVES ADDED IN 1974

[7-percent inflation, no depletion allowance; in millions of dollars]

Year	Total invested capital	Depreciation and cost depletion	Total assets (adjusted basis), year end	Stockholders' equity, year end	Adjusted gross income	Intangible drilling expenses (tax calculation)	Depreciation and cost depletion (tax calculation)	Interest expense	Taxable income	Investment tax credit	Federal income tax	Net income after taxes	Net income after taxes plus interest	After tax return on stockholders' equity (percent)	After tax return on total capital (percent)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
1974	4,491	168	4,323	2,378	414	2,635	98	175	−2,494		−1,247	1,318	1,493	55.4	34.5
1975		314	4,009	2,855	886		184	162	590	66	204	206	368	7.2	9.1
1976		291	3,718	2,045	952		171	151	630		315	195	346	9.5	9.3
1977		268	3,450	1,896	1,018		157	139	722		361	250	389	13.2	11.3
1978		158	2,192	1,756	1,085		151	129	805		402	296	425	16.8	13.3
1979	197	239	3,159	1,732	1,159	145	140	128	746	4	363	423	551	24.4	17.4
1980		230	2,920	1,606	1,242		135	118	989		444	450	568	28.0	19.4
1981		213	2,707	1,489	1,304		125	110	1,069		534	447	559	30.0	20.7
1982		198	2,509	1,380	1,248		116	102	1,030		515	433	535	31.3	21.3
1983		183	2,326	1,279	1,168		107	94	967		484	407	501	31.8	21.5
Average*														24.0	17.6

*Average return from geometric mean of 1+R.

Notes (Cols. (1) and (5) inflated at 7 percent per year):
(1) LaRue, Moore and Schafer, table 26, col. 8.
(2) and (7), depreciation and cost depletion calculated by double declining balance method, 27.58 year economic life.
(3) (1), adjusted by (2).
(4) 55 percent of (3).
(5) LaRue, Moore and Schafer, table 26, col. 7.
(6) LaRue, Moore and Schafer, table 26, col. 13.
(8) 9 percent of 45 percent of (3).
(9) (5)−(6)−(7)−(8).
(11) 50 percent of (9), — (10).
(12) (5) — (11).
(13) (12) + (8).
(14) (12)/(4).
(15) (13)/(3)

AN EXAMINATION OF "WINDFALL PROFITS TAX" ON OIL AND GAS PRODUCTION

(By Martin G. Miller and Max R. Lents)

OBJECTIVE

The purpose of the following is to examine and comment upon the proposals now being considered by committees of the Congress with regard to:

> A "Windfall Profits Tax" on oil and gas production discovered prior to December 1, 1973. Said tax to be levied against such production which is sold at prices exceeding: Oil—$4.95 per Bbl.; Gas—$0.94 per MCF.

The Domestic Oil Industry as discussed herein is limited to those activities and data pertaining to the oil industry in the United States, exclusive of the recently discovered (1968) North Slope-Prudhoe Bay Area of Alaska. The latter area is excluded from consideration because the expenditures associated therewith to date in no way reflect the costs which will be eventually incurred because of the difficult and unknown problems that will be associated with developing, operating, and transporting oil and gas from this remote area which is subject to climatic conditions not heretofore experienced in actual practice. This reservation should in no way be interpreted as casting an adverse opinion as to the merits and ultimate value of these activities in Alaska. However, at this writing such oil and gas reserves, their magnitude and associated costs (actual and estimated) should not be included in a consideration of the data pertaining to the *Domestic Oil Industry* as defined here.

INTRODUCTION

Before forming a judgment with regard to the idea of levying a "windfall profits" tax on the domestic oil industry, it is desirable to examine certain facts with regard thereto for the purpose of determining whether or not a situation exists that justifies such a tax.

It is our view (Max R. Lents and Martin G. Miller) that a correct and elemental method with which this problem may be analyzed is analagous to the effect of inventory accounting upon the stated profits of many public corporations.

It is generally acknowledged that many company's profits were overstated during the last three quarters of 1974 because of inventory profits. This overstatement occurred, of course, because in periods of rapidly rising prices firms tend to make a profit on the increase in value of their inventories, whether raw materials, goods in process of being manufactured, or finished products.[1] Such inventory profits were estimated by the U.S. Department of Commerce to be at an annual rate of $37.3 billion during the second quarter of 1974—nearly *one-third* of all pretax profits of non-financial corporations.[1]

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[1] Please refer to First National City Bank Monthly Economic Letter, August 1974, for a discussion of inventory profits from which this was derived.

Corporations using the "First In First Out" (FIFO) method of accounting for inventories show such "phantom profits" as income for book purposes and, as a result, a very large number of such companies changed during 1974 to the accounting basis where the value of the *last*, rather than the first, unit of raw material bought for manufacturing or goods purchased for sale was charged to expense in order to avoid an overstatement of earnings during the time when the price of raw materials or goods sold was rapidly increasing. The latter accounting method for inventories, of course, is referred to as Last In First Out or (LIFO).

At the risk of being repetitive, when prices are rising the *profits* of a *FIFO corporation* are *an illusion* to the extent that the cost of the last goods purchased for inventory exceeds the cost of the first inventory goods purchased since the company must at once replace such lower cost goods with goods at the higher price *or liquidate its business.*

The *production* of oil and gas is the activity at which the "Windfall Profits" tax is directed and it is only this activity which is considered and referred to herein as the "producing business". Most oil companies are, of course, engaged in many manufacturing and marketing activities utilizing oil and gas as raw materials to which the "windfall profits" is not applied and with which we are not concerned here.

The stock in trade of the producing business is oil and gas, which are obtained by exploration and development.[2] The developed underground supplies of oil and gas are referred to as "reserves" and are the inventories which must be maintained or increased, if the domestic producing companies are to stay in business. Domestic Oil Reserves (underground inventories) represented about 8 *years'* supply at the *1973 producing rate. Aboveground* oil inventories at that time were negligible, being about *0.8 percent* of *underground oil reserves.* Domestic Gas Reserves were equal to about *10 years'* supply at the *1973 producing rate.* No gas is inventoried aboveground by producing companies and, for practical purposes, this is true of all industry.

To our knowledge the publicly stated profits of producing companies do not fully reflect the present cost of replacing oil and gas produced and sold or used. Accepted accounting methods vary considerably but usually fall within two categories: (1) "*Successful Efforts*" *Accounting*—Substantially all exploration costs (dry holes, abandoned leases, delay rentals, etc.) are currently expensed and productive development costs are capitalized and amortized over the useful life or on a unit of production basis. (2) "*Full Cost*" *Accounting*—All exploration and development costs are capitalized and amortized on a unit of production basis.

Method (2) treats the weighted average historical cost of finding and developing oil and gas as an expense of producing oil and gas during the year. Method (1), more generally used by older, large companies, treats only a relatively small portion of past exploration costs of finding oil and gas (most of those costs having been expensed in previous years) and also only a portion of past development costs as an expense when the oil and gas are produced. In connection with the development costs it is significant to note that about 60 percent of

[2] Or by purchase of developed or partially developed underground reserves.

the Domestic Oil Reserves are contained in 99 [3] (giant) fields, the average discovery date [4] of which is 1936 or 39 years ago. Obviously, in the situation where the weighted average reserve has an age of 39 years the development costs have been largely amortized or depreciated.

In connection with the Method (1) companies, it is significant to note that their holdings in the older "giant fields" mentioned above are substantial; and further, the published statements of Method (1) companies do not show the actual current cost of replacing oil and gas reserves. This is true because a substantial portion of the cost of finding these reserves (which were discovered and developed some 40 years ago) was either initially expensed in prior years or has now been substantially written off. Although Method (1) companies also expense certain current year exploration costs, this only reflects the current year level of exploration activity, and it is not directly related to the quantities of reserves produced.

It is obvious that the accounting statements of neither Method (1) nor Method (2) companies show the current cost of replacing underground inventories as an expense.

Past and present government regulations of gas prices and current government regulations of oil and natural gas liquids prices preclude the generation of internal funds sufficient to replace underground inventories of such products.

In the past ten years the underground inventories of Domestic Gas Reserves have declined from an 18 years' supply to a 10 years' supply. During the same period underground Domestic inventories of oil have declined from a 12 years' supply to an 8 years' [5] supply based on Domestic oil consumption and production, despite increasing importation of oil from foreign sources.

Summary and Conclusions

We asked two questions in order to examine the validity of the windfall profits tax concept. These questions and the answers reached are:

1. What was the cost to the Domestic Oil Industry of finding and making available new oil to replace old oil removed from underground inventories during 1973?

   Answer: Data applicable to the Domestic Oil Industry as a whole indicate that the cost during 1973 of finding and making available new oil to replace old oil removed from undergroupnd inventories was in excess of *$9 per barrel.* This is without *any allowance* for *interest* or *profit* on the *funds invested* to acquire this new underground inventory.

   If the Domestic Oil Industry had, during 1973, used the LIFO method of accounting and charged to expense the value of oil inventory sold at the *$9.83 replacement cost*, it is obvious that oil industry profits would have been substantially less than reported. No "Windfall Profits", of course, would have occurred.

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[3] Source—American Petroleum Institute, published in Oil & Gas Journal, April 21, 1975.
[4] This date is weighted with respect to presently remaining reserves in these fields.
[5] Based on 1973 requirements.

2. At what average price must the Domestic Oil Industry have acquired its underground inventories of oil in order to make a profit from selling 1973 production at the Windfall Profits Tax base price of $4.95 per barrel?

Answer: For a rate of return, *before Federal Income Tax*, of 6 percent on the capital invested in underground inventories of oil, such oil must have been acquired at an average cost of *10 cents per barrel;* for a rate of return of 8 percent, at *5 cents per barrel.*

The weighted average domestic reserves produced in 1973 from underground inventory had been in inventory about 39 years. The 1936 dollars with which the inventories were acquired were worth substantially more than 1975 dollars. Even though oil was easy to find in 1936 by today's standards and was found at relatively shallow depths (4000 feet to 6000 feet), the acquisition costs per barrel (finding plus development or purchase) were substantially greater than the values (5 to 10 cents per barrel) calculated above.

When one considers that the oil industry requires a rate of return on capital, because of the risk involved in prospecting, above that required in other industries, the above data show that a Windfall Profits does not exist even at the current price for "new (uncontrolled) oil", which is presently about $11–$12 per barrel.

The price provisions of the windfall profits tax appear to have little practical application to the production phase of gas operations because regulations of the Federal Power Commission, various state public utility commissions and the price provisions in long-term contracts covering unregulated gas combine to produce market prices for produced gas substantially below the base price in the Windfall Profits Tax proposed legislation.[6] There are insufficient data available to us to make it feasible to determine either the volume or location of unregulated gas not subject to these restrictive price conditions. Thus, we are unable to form a conclusion with regard to the effect of the Windfall Profits Tax on that portion of the produced gas supply to which the proposed tax is applicable.

A continuation of the two-tier pricing system of oil, *the triple tier pricing system for natural gas liquids*, the unrealistic price regulations imposed upon the sale of natural gas and the Windfall Profits Tax now being considered inevitably will result in the *demise* of the *Domestic Oil Industry* due to the denial of the internally generated funds necessary for its existence.

There may be some who feel that the Doemstic Oil Industry and the funds it requires are not an important aspect of the solution of the "energy crisis" now facing this country. In our opinion, a careful appraisal of the alternate sources of energy, their cost, associated requirements (fresh water, transportation, etc.), and time to develop will show they are not the panacea claimed by many as a solution. Oil and gas priced in a free market will be our cheapest sources of energy for the foreseeable future. We firmly believe that there are

[6] Published average natural gas prices by FPC for interstate gas sales and by U.S. Bureau of Mines for average natural gas for *both* intrastate and intrastate marketed production are essentially the same for the period.

wise and prudent areas of *risk investment* in the Domestic Oil Industry; i.e.,

1. Extended exploration and development of the continental offshore areas (Pacific, Gulf, and Atlantic).
2. Deeper drilling in existing petroliferous provinces.
3. Expansion of exploration to adjacent basins.
4. Development of low producing capacity gas accumulations (noncommerical at FPC permitted prices).
5. *Real field wide testing* of the possibilities of *tertiary oil recovery.*

We believe that all of these measures will be undertaken by private industry if it is permitted earnings commensurate with the risk.

Discussion

In our analysis of question 1 as set forth in the Summary and Conclusions, certain public data exist which permit an arithmetic approximation of the present day cost of replacing oil and gas underground inventories. The methods used, assumptions employed, and adjustments required to obtain this approximation from the data available are discussed in more detail in appendix I, attached.

The data needed for such an analysis are quite simple and consist of the following:

1. The annual cost of exploration and development for oil—$.
2. The quantity of oil reserves added by such expenditures—barrels.
3. The unit cost of producing these oil reserves—$ per barrel.

The annual cost of replacing oil taken from underground inventory is calculated by adding Item 3 to the amount obtained by dividing item 1 by item 2.

Oil industry total exploration and development expenditures were obtained from the pamphlet "Capital Investment from the World Petroleum Industries, 1973" published by Chase Manhattan Bank. Additions to natural gas liquid and gas reserves were derived from API, et al., Reserve Reports [7] for the years involved.

Two major assumptions were necessary in order to utilize the data available for approximating applicable present day cost of replacing oil and gas withdrawn from underground inventories. These were:

(A) It is impossible to identify exploration costs between oil and gas. Such an identification of development costs is not available to us and, if available, in our opinion would have little meaning, since, as a practical matter the producing business sells gas to a largely government regulated market and, where not regulated, under long-term contracts. We have, thus, simply subtracted from exploration and development costs for a particular year the net working interest value of gas reserves found during the same year. Gas prices used were FPC average gas prices for each year. The remainder of such costs must, obviously, be recouped from oil and are allocated to oil in our analysis. It was noted that the present worth of gas reserves added during 1973 if sold at the present FPC national area price of 56.6 cents per MCF (including

[7] Joint reports of American Gas Association, American Petroleum Institute, Canadian Petroleum Association.

severance taxes) is about the same (23.5 cents per MCF) as the 1973 gas price used of 22.5 cents per MCF.[8]

(B) Proved oil reserves, as determined by the API Committee on Reserves, are included within its statistics only when they are proved by the drilling of wells. Such initial reserves may later be revised up or down due to field performance or secondary or tertiary measures employed to increase recovery. Reserves of gas have generally been revised down in recent years due to poor performance or inaccurate initial reserve estimates. Revisions to oil reserves have generally been up due, in our opinion, to (1) the greater accuracy of scientific devices for physical measurements of oil field properties now available to engineers and (2) institution of secondary production mechanisms in older, "giant" oil fields. Since these revisions to reserves apply almost entirely, in our judgment, to old fields, they have little or no bearing upon quantities of new oil discovered so are not included in the "oil reserves discovered" category.

Table I, attached, shows the computations of the cost of replacing inventory oil produced by years through 1973. *This cost was $9.83 per* barrel for 1973. We have seen a recent analysis of the cost of drilling and equipping wells which showed that this cost has increased 41% during the past 18 months. Therefore, if the 1974 oil finding rate is the same as for 1973, the 1974 cost per barrel maybe substantially higher than for 1973.

The figures shown include only the costs of finding, developing, and producing oil. In order to generate some rate of return[9] on the investment, the oil must be sold at prices greater than these costs.

It will be noted that the costs of *adding oil* (finding, developing, and producing) has accelerated upward from about $3.89 per barrel in 1969 to a figure in excess of $9 per barrel in 1973. There are a number of factors which enter into this steady incretase which are:

1. The general inflation which has occurred in the economy as a whole.
2. Increasing costs of certain aspects of the oil industry, in particular, costs such as labor, tubular goods, drilling operations, and the reduction of the finding rate of both oil and gas.
3. Increases in the large sums spent for lease bonuses (*paid to the Federal government*) for offshore leases in recent years.

All of these factors serve to increase the presently indicated finding costs of oil and making it available for market.

In our analysis of question 2, "At what average price must the Domestic Oil Industry have acquired its underground inventories of oil in order to make a profit from selling 1973 production at the Windfall Profits Tax base price of $4.95 per barrel?", we have given consideration to the following items:

The time that the oil reserves have been in storage is one of the most significant factors in determining whether or not the proposed price levels for a windfall profits tax are realistic in view of both the *storage period* and the *economic conditions* existing at the time of the weighted average discovery date.

[8] Pages ii and iv of appendix I discuss gas prices used.

[9] The magnitude of the rate of return must recognize the substantial risk involved in searching for oil and gas.

We have previously mentioned that about 60 percent of the domestic oil reserves as of December 31, 1974 exist in some 99 fields. These reserves were discovered in periods ranging from prior to 1900 up until the discovery of the Jay Field in (Florida) 1970. We have used the remaining oil reserves listed for these fields and arranged the reserves of these fields into groups commencing in 1900 at 5-year time intervals, depending upon the discovery date. No adjustment was made for fields found prior to 1900. No attempt was made to determine with precise accuracy, the dates of extensions, of the finding of deeper reserves in these fields, etc. The reserves for each 5-year period were multiplied by the intervening years between the period and 1975. The product (barrel-years) was divided by the number of total remaining reserves in said fields. The weighted average storage period (by this method is 39 years. The question then arises, "What is the weighted average storage period of the remaining 40% of domestic reserves?" Time and information available to us did not permit a detailed analysis of this matter, however, the reports of the API Committee on Reserves included a table which lists the *initially proved reserves* developed in each year. An analysis of this table (which contains all of the Domestic reserves) shows a very similar distribution with respect to weighted average discovery date as that indicated by the analysis of the 99 fields mentioned above. For this reason, we believe that it is reasonable to analyze the above question on the basis that our existing domestic reserves were found,[10] developed, and/or acquired some 40 years ago.

This being the case, one must realize that such reserves were acquired with dollars worth considerably more in purchasing power than those received today. We believe that an adjustment in the order of six [11] must be made to the 1975 price levels to make them equivalent to those applicable to the oil industry in the period around 1936. When this is done and current production costs have been subtracted, the $4.95 figure proposed as a beginning point for the Windfall Profits Tax becomes approximately *$0.67 per barrel* ($4.95 − 0.92 ÷ 6 = $0.67).

Another factor which must be considered is that in the period around 1936 such data as were available with regard to unit (per barrel) costs of finding and developing or acquiring oil reserves were usually based upon reserve estimates that were, for the most part, understated by today's standards. Accordingly, we feel that an adjustment must be made for this factor. We have therefore assumed that *one barrel* which was acquired for developed in 1936 *actually represented about 1.5 barrels*, in view of the more accurate reserves estimates which now can be made as well as the improvement in production practices which have subsequently been accomplished leading to increased oil recovery. Thus, the *$0.67 per barrel* should be multiplied by *1.5* ($0.67 × 1.5 = $1.01). It is this value (*approximately $1.00*) that must be discounted at some interest rate to determine the capital required in 1936.

If a rate of return, *before Federal income tax*, of 6 percent is permitted, then an *initial investment* of *$0.10* would have been required to produce $1.00 in 1975 with no depreciation of currency. If an 8% rate of return is used, $0.05 would be required as an investment to

[10] On the weighted average.
[11] 1975 prices ÷ 6 = 1936 prices.

produce $1.00 in 1975 with no depreciation in the relative purchasing power of the currentcy.

Records available to us indicate that it was not possible to find and develop or to acquire underground reserves at unit costs commensurate with these figures (*$0.05 to $0.10 per barrel*) in any substantial volume relating to the underground inventory as a whole. Obviously, there were, and still are, exceptions to all groups of statistics. In other words a single discovery or acquisition may be considerably profitable but it must be balanced against those that are less profitable. Our comments here are directed to conditions applying to the *domestic industry* as a *whole* at that *particular time period* and under the circumstances described above.

TABLE 1.—UNITED STATES (EXCLUDES PRUDHOE BAY FIELD ON NORTH SLOPE OF ALASKA)

Year	Exploration and development expenditures (millions)	New petroleum reserves during year due to extensions and discoveries				Average gas price (FPC) per MMCF	Production costs gas per MMCF	Net working interest gas income (millions)	Exploration and development expenditures attributable to liquid reserves		Production costs per barrel	Exploration development and production costs per per barrel
		Crude oil (million barrels)	Natural gas liquids (million barrels)	Total (million barrels)	Natural gas (million MMCF)				Millions	Per barrel		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1966	$4,420	1,124	260	1,384	15.282	$169	$50	$1,546	$2,874	$2.08	$0.72	$2.80
1967	4,640	1,061	259	1,320	15.234	171	48	1,593	3,047	2.31	.70	3.01
1968	5,640	1,134	216	1,350	10.680	173	50	1,117	4,523	3.35	.72	4.07
1969	4,275	862	175	1,037	9.613	175	50	1,021	3,254	3.14	.75	3.89
1970	5,000	1,000	272	1,272	11.296	181	52	1,239	3,761	2.96	.78	3.74
1971	4,100	717	213	930	11.054	190	55	1,268	2,832	3.04	.83	3.87
1972	6,655	737	200	937	10.713	205	59	1,329	5,326	5.68	.83	6.51
1973	8,290	594	177	771	10.299	225	63	1,418	6,872	8.91	.92	9.83

Col. (1): Adapted from Chase Manhattan December 1974 "Capital Investments of the World Petroleum Industry" study.

Cols. (2) (3) (5): From "Petroleum Reserve Report" December 31, 1973 published jointly by American Petroleum Institute and others.

Col. (4): Sum of cols. 2 and 3.

Col. (6): From "FPC News," publication of Federal Power Commission.

Col. (7): Production costs for gas include direct operating, overhead, severance and ad valorem taxes. Based on American Petroleum Institute studies and certain oil company cost statistics.

Col. (8): Col. 5 times 0.85* times (col. 6 less col. 7). *0.85—the working interest portion of the gas reserves, col. 5.

Col. (9): Col. 1 less col. 8.

Col. (10): Col. 9 divided by col. 4.

Col. (11): Same source as shown for gas in col. 7.

Col. (12): Sum of cols. 10 and 11.

Appendix I

Cost of Crude Oil

The cost of finding and developing new crude oil reserves[1] are analyzed for the years 1966 through 1973. The results of this analysis are shown in Table 1. It will be noted on the table that the costs attributable to exploration and development expenditures start at $2.08 per barrel in 1966 to $8.91 per barrel in 1973. In addition to these per barrel costs, the operating expense, estimated to be $0.92 per barrel in 1973, must be added in order to account for the production cost per barrel. This total cost shown in the right-hand column of finding, developing, and producing the new crude oil reserves is $9.83 per barrel for the year 1973.

In making this study, various published data were available from the following sources:

1. Capital Investments of the World Petroleum Industry, December, 1974. This is an annual study made by the Chase Manhattan Bank.
2. The Reserves of Crude, Natural Gas Liquids and Natural Gas in the United States and Canada and the United States Productive Capacity as of December 31, 1973. This report is published jointly by the American Gas Association, American Petroleum Institute and Canadian Petroleum Association.
3. Average Price of Gas Purchased from Domestic Producers by Interstate Pipe Lines. This is monthly data presented graphically in the FPC News, a publication of the Federal Power Commission.

The Chase Manhattan Bank report, as mentioned above, presents a detailed study of the financial expenditures of a large number of oil companies beginning with the exploration phase for oil and gas through the marketing phase of the finished products derived from oil and gas. However, in the analysis as shown on the accompanying table, we have only used the expenditures relating to the exploration and development phase reported in the Chase study. These expenditures are shown in column 1. Column Nos. 2, 3, and 5 contain the changes in petroleum reserves during the year due to extensions and discoveries. These data are taken from the reserve report prepared by the American Petroleum Institute, *et al.* The change reported as revisions in the reserve report was not included in the above changes and the reason for this will be discussed later. These changes, it will be noted, include those for crude oil, natural gas liquids and natural gas. The average annual gas price by years is shown in column 6. These data were taken from the FPC records and represent the prices paid domestic producers by the interstate pipeline companies. The net gas price shown in the next column represents the gas production costs which include the direct operating expenses, overhead and severance and production taxes. Column 8 shows the net gas income which is determined by multiplying the gas price less the production costs times the natural gas reserves shown for each year. In column 9 is shown the exploration and development expenditures after deducting the net gas income. Here, for purposes of dividing the exploration and devel-

[1] Includes natural gas liquids.

opment expenditures between oil and gas, we have simply said the expenditures required to find and develop the new gas reserves is equal to the net gas income shown in column 8. In other words, the expenditures, column 9, as shown, are attributable to the new liquid reserves, crude oil and natural gas liquids for the particular year. Column 10 shows these costs calculated on per barrel basis for the new liquid reserves for each year. These per barrel costs, it will be noted, are for exploration and development expenditures only. An additional cost, the cost of producing the liquid reserves, column 11, must be included as part of the total costs as shown in column 12.

As has been pointed out previously, the analysis herein has not included the Prudhoe Bay Field located on the North Slope in the State of Alaska, since there are a great number of unknowns regarding investments and expenses which will be large and which will occur in the future. Production from this field has not begun and is not expected to commence until mid-1977 because the necessary pipeline facilities, devolpment wells, storage facilities, and tanker facilities have not been completed. Originally, the pipeline was estimated to cost $900 million but due to increasing cost of materials and additional requirements by government regulatory bodies, the current estimate of the cost of the pipeline is approximately $6 billion. One can see from this change in the cost of just one phase of getting this very large field on production that it is very difficult to come to grips with the real information regarding investments as well as operating cost for this project since this is the first large field found in the Arctic Area of North America. With reference to the operating expenses, the field, it will be recalled, is in one of the most harsh and changeable environments in the world. The cost to operate under these conditions is unknown at this time. For these reasons, we have deducted the expenditures attributable to this field from the Chase study. Likewise, the Prudhoe Bay reserves, both oil and gas, have been deducted from the API reserves.

As previously mentioned for the year 1973, the cost of exploring, developing, and producing the new reserves found for that year was computed to be $9.83 per barrel. In the years previous to 1973, it will be noted, from 1966 through 1971 that there was only a modest increase; that is, from $2.80 in 1966 to $3.87 in 1971. However, a dramatic increase in the per barrel costs took place in 1972 as well as 1973. A large part of the increased costs of these two years can be attributed to the large increase in exploration costs of acquiring new leases. For the three previous years (1969, 1970, 1971) prior to 1972, the lease acquisition costs were $350 million, $1.1 billion and $300 million, respectively. However, for 1972, the lease cost increased to almost $2.5 billion and for 1973, it increased further to $3.6 billion. It must be remembered that in all probability, a great majority of these leases will require 2 to 5 years to be explored and if commercial quantities of hydrocarbons are found to be developed.

With regard to the new reserves shown on table 1, for each of the years this includes the extensions and discoveries taken from the API reserve report. The extensions include additional reserves where a given field has been enlarged during the year. New discoveries included new field discoveries in which there is no nearby production and discoveries in new reservoirs not known before. The "revisions"

shown in the API report [2] generally are those changes (decrease or increase) in reserves due to additional engineering and geological data available and due to the institution of secondary recovery operations in older fields. These types of changes; that is, revisions, are not included in our analysis since it was felt that these types of changes are due principally to secondary recovery type of operations and additional reservoir information including performance and have little bearing with regard to reserves added by exploration and development in a particular year. To verify the conclusions concerning the reserve "revisions" as reported in the API reserve reports, the detailed revisions for the years 1971, 1972 and 1973 are examined by States and districts within certain States. The revisions reviewed represented in terms of volumes 88 percent, 88 percent and 95 percent, for the years 1971, 1972, and 1973, respectively, of the total revisions reported for the United States. For example, in 1973, the State of Texas had a net revision of 371 million barrels (net [3]) in the Permian Basin Area. This large revision for this area is due primarily to the large number of secondary recovery projects being installed. As far as is known, there has not been any major new fields found recently which would account for a revision of this magnitude due to additional reservoir data becoming known. Net revisions amounting to 803 million barrels represents another illustration of the change in this same area for the year 1971. Again, secondary recovery projects were being instituted at a rapid rate in a number of giant-type fields, such as Wasson, Slaughter and Levelland fields.

We have assumed in this analysis that the Chase report on exploration and development expenditures does not include any costs relating to secondary recovery projects. There is no mention of this type of expenditure in their reports. However, we have checked the possible differences it would make in the oil costs (per barrel) if the secondary recovery costs are in the Chase report based on the secondary recovery costs reported by the API.[4] By deducting these API costs from the expenditures attributable to liquid reserves, Column 9, Table 1, the per barrel costs in Column 12 in Table 1 are reduced by approximately 5 percent. For example, the per barrel cost for 1973 of $9.83 as shown in Column 12 would be reduced to $9.48 per barrel.

On the other hand, it is possible to derive the exploration and development costs, exclusive of "Improved Recovery Programs" from the API for the five years 1969 through 1973. These costs differ from and are higher than the Chase figures for the same period by about 8%. We have used the lower costs of the Chase study in this analysis.

Average national gas price which includes both *intrastate* and *interstate* marketed production reported by the Bureau of Mines could have been used instead of the FPC price. The Mines average price is slightly lower than the FPC price (5% to 9% for years 1966 through 1972). The lower price of gas in turn increases the cost of oil 2% to 3%. For example in 1972 the oil cost increases from $6.51 to $6.65 per barrel, Table 1, Column 12.

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[2] See extracts of API Report at end of this section.

[3] Increases in revisions amounted to 444 million barrels whereas decreases amounted to 73 million barrels.

[4] 1973 Joint Association Survey, Section II, Table I.

Another approach to determination of value of gas reserves added during a given year was considered. It was assumed that gas discovered in 1973 would be sold at a constant rate during a 20 year period at the present FPC national rate of 56.6 cents per MCF, which includes severance taxes. Discounting this future income at 8% resulted in the computation of present worth of gas reserves added during 1973 of 23.5 cents per MCF. This compares with the gas price of 22.5 cents per MCF used in our determination of cost per barrel of oil reserves added in Table I. The effect of using this method was considered negligible.

The following definitions and discussions have been extracted from the API reserve report for 1973 (pages 15 and 16): Discoveries, Extensions, Revisions, Proved Acreage and Improved Recovery Techniques.

Discoveries. Discoveries reported as of December 31 for any given year are proved reserves credited to new fields and new reservoirs in old fields as the result of successful exploratory drilling and associated development drilling during the current year.

The reliability of estimates of the proved productive area of new discoveries or partially developed reservoirs varies in relation to the amount of geological information available at the time the estimate is prepared. Important factors such as the areal extent of the structure, the average thickness of the producing reservoir, the oil column within the reservoir, and the continuity and characteristics of the reservoir formation cannot be determined accurately unless sufficient subsurface information is available.

The ultimate size of newly discsovered reservoirs, whether in new fields or old fields, is seldom determined in the year of discovery. Therefore, first-year estimates of proved reserves in new reservoirs are often only a small part of the total that will be ultimately assigned to the new reservoirs. It follows that reserves credited to discoveries in any given year are usually less than total extensions and revisions for the same year, since extensions and revisions represent adjustments of reserves in reservoirs discovered in all prior years.

Subcommittees are not necessarily aware of and may not have access to the subsurface information for all new discoveries at the time reserve estimates are prepared. This is especially true if a discovery is made late in the year for which a report is being prepared or when competitive situations dictate that the subsurface information be held as proprietary. In such cases, new proved reserves are reported in Table I as discoveries in new fields or new reservoirs in old fields for the year in which the discovery becomes known or when subsurface information becomes available. In Table III, these reserves are assigned to the year in which the field was actually discovered.

Extensions. The ultimate size of newly discovered fields, or newly discovered reservoirs in old fields, is normally determined by drilling in years subsequent to discovery. Wells drilled in subsequent years usually add to the proved area of previously discovered reservoirs, thereby serving to increase estimates of proved reserves. The reserves credited to a reservoir because of enlargement of its proved area are classified as "extensions."

Revisions. Both development drilling and production history add to the basic geological and engineering knowledge of a petroleum reservoir and provide the basis for more accurate estimates of proved reserves in years following discovery. Changes in earlier estimates, either upward or downward, resulting from new information (*except for an increase in proved acreage*) are classified as "revisions." Revisions for a given year also include (1) increases in proved reserves associated with the installation of improved recovery techniques; and (2) in amount which corrects the effect on proved reserves of the difference between estimated production for the previous year and actual production for that year. [Emphasis added is ours.]

Proved Acreage. Proved acreage is that which has been credited with proved reserves. Acreage is credited with proved reserves if the presence of a productive formation has been verified by drilling and testing. *Undrilled acreage adjacent* to drilled acreage and certain other undrilled acreage we also credited with proved reserves if *geological and engineering information* demonstrate with *reasonable certainty* that the underlying formations *are continuous and productive.* [Emphasis added is ours.]

Improved Recovery Techniques. Improved recovery techniques include all methods for supplementing natural reservoir forces and energy, or otherwise increasing ultimate recovery from a reservoir.

Such techniques include: (1) pressure maintenance; (2) cycling; and (3) secondary recovery in its original sense; (i.e., fluid injection applied relatively late in the productive history of a reservoir for the purpose of stimulating production after recovery by primary methods of flowing or artificial lift has approached an economic limit). Improved recovery techniques also include thermal methods and the use of miserable displacement fluids.
listed above are reported as "*revisions*" to proved reserves for the year

Reserves resulting from the application, of *any of the method;* in which successful *testing by a pilot project* or the *operation of an installed program in the reservoir* provides support for the engineering analysis on which the project or program was based. [Emphasis added is ours.]

"STAFF ANALYSIS OF THE COST OF FINDING AND PRODUCING NEW CRUDE OIL," BUREAU OF NATURAL GAS, FEDERAL POWER COMMISSION, JUNE 1975

FEDERAL POWER COMMISSION,
Washington, D.C., June 27, 1975.

Hon. WARREN G. MAGNUSON,
Chairman, Committee on Commerce,
U.S. Senate, Washington, D.C.

DEAR CHAIRMAN MAGNUSON: I am pleased to forward the attached analysis prepared by the Commission's Bureau of Natural Gas, in consultation with our Office of Economics, in response to your letter of June 20 requesting a computation of "the cost of new domestic crude oil in 1974 based on nationwide cost and drilling data comparable to your natural gas costs."

As explained in the report, the computation is based on a 15 percent rate of return according to a discounted cash flow method of analysis and constant annual production rates over an 18-year depletion period. The underlying costs are for 1973, which is the latest year for which the necessary data are available. The computations show an estimated cost of $6.12 per barrel before Federal income taxes and excluding State production taxes. A rough allowance for Federal income taxes, including this year's change in percentage depletion, raises the estimated cost to between $6.76 and $9.17 per barrel.

In closing, I wish to stress the qualifications expressed by the staff regarding the assumptions underlying the cost estimate. Because of the brief time in which the estimate had to be prepared and the lack of prior experience with costing for crude oil, the staff advises considerable caution in using the cost estimate.

We will be pleased to answer any questions you have regarding the staff analysis.

Sincerely yours,

JOHN N. NASSIKAS, *Chairman.*

Enclosure.

STAFF ANALYSIS OF THE COST OF FINDING AND PRODUCING NEW CRUDE OIL—BUREAU OF NATURAL GAS

This cost analysis was prepared in response to an inquiry made by letter dated June 20, 1975, from Chairman Warren G. Magnuson on behalf of the Senate Commerce Committee concerning the cost of new domestic crude oil based on this Commission's methodology used to cost new natural gas. The computations as shown on the attached schedules indicate a cost estimate of $6.12 per barrel of new crude oil based upon the most recent available data and a number of underlying assumptions. This cost excludes production taxes which vary among the State Domains and assumes no payment of Federal Income Taxes. The costing method used in this analysis is similar to that used

by this Commission in estimating the nationwide cost of finding and producing non-associated gas. Alaskan data were excluded, where possible, from the analysis.

It should be emphasized that the costing of new crude oil is novel to Staff and unlike the costing of gas, Staff lacks the experience and knowledge gained from the many case records involving gas producer proceedings. Therefore, it is imperative that recognition be given to the probable imprecision that is inherent in this type of analysis. Much of the available data were extracted from gas industry publications and the data were not audited and verified by Staff. It is also important to be aware of the underlying assumptions in this analysis which are as follows:

(1) A 15% rate of return or true yield was used for crude oil which is the same rate of return used by this Commission for natural gas.

(2) The discounted cash flow (DCF) method was employed. The use of the DCF method requires knowledge of the timing of exploration and development expenditures made prior to production and the annual rates of oil production for a typical or average oil well. Staff used an 18 year depletion period, constant annual production rates and the same timing of preproduction expenditures as that for gas well gas. These elements are crucial in estimating the unit return allowance and may differ significantly for crude oil.

(3) Payment of Federal Income Taxes was assumed to be zero. The repeal of the depletion allowance law makes this assumption unlikely. Actual taxes to be paid resulting from natural gas revenue is under study by Staff. The problem of determining actual taxes or even reasonable estimates is extremely complex because a nationwide average tax must be determined for thousands of gas or oil producers and each may be in a different tax status or liability. The problem is further complicated when taxes are to be determined for new gas apart from old or flowing gas and similarly for crude oil. It is questionable whether a reasonable solution can be attained based on available information.

(4) This analysis reflects the most recent available data which is generally through the year 1973. Costs were not trended because a myriad of factors must be studied and informed judgment or statistical methods, if applicable, must be applied. These factors include inflation, success achieved on Federal leases where large bonuses have been paid, the depth and geographic pattern of oil drilling, changes in new oil prices, the repeal of the depletion allowance and possibly other factors. Most of these would exert an upward pressure on new oil costs. In addition it should be understood that the indicated cost result is an *average* nationwide cost which does not represent the higher cost of marginal oil drilling projects.

In conclusion, it should be recognized that this cost analysis was prepared during the brief time made available and the various cost elements were estimated on the basis of available data and the limited knowledge of Staff concerning new crude oil production. This limited knowledge makes suspect certain of the underlying assumptions involved in the cost study. Therefore, Staff suggests cautious use of this cost analysis for any regulatory purposes.

The unit cost of $6.12 per barrel was estimated on the basis of zero income taxes and therefore should be considered at the low side of any cost range. For illustrative purposes Staff made two additional cost calculations including positive tax liabilities as follows: (1) $6.76 per barrel, 22% (prior depletion allowance) of gross income less royalty is assumed to be taxed at the rate of 48% (2) $9.17 per barrel, the return on investment less 2.4% for interest on debt is assumed to be taxed at the rate of 48%. Both of these costs are rough estimates because the full effect of intangible drilling cost deductions is unknown and was not considered.

(Prepared by Louis J. Engel, Supervisory Regulatory Gas Utility Specialist.)

SCHEDULE NO. 1

COST OF FINDING AND PRODUCING A BARREL OF NEW CRUDE OIL (LOWER 48 STATES)

Line No.	Item description	Source	Unit, per barrel
1.	Oil well drilling cost	Schedule 3	$0.53
2.	Lease acquisition cost	do	.46
3.	Production facilities	do	.33
4.	Subtotal		1.32
5.	Dry hole drilling cost	Schedule 3	.26
6.	Other exploration cost	do	.24
7.	Exploration overhead	do	.07
8.	Subtotal		.57
9.	Operating expense	Schedule 3	.88
10.	Casinghead gas credit	do	(.61)
11.	Return on working capital	do	.14
12.	Return on investment	do	2.84
13.	Royalty at 16 percent	Schedule 2	.98
14.	Total excluding production tax	do	6.12

SCHEDULE NO. 2

COMPUTATION OF PRICE BY THE DCF METHOD

	Preproduction costs	Year	Value	Tax credit	Net investment	15 percent present value
1.	Other exploration	3	$0.24	0.109	0.131	0.19
2.	Exploration overhead	3	.07	.032	.038	.05
3.	Lease acquisition	2	.46	0	.46	.60
4.	Dry holes	1	.26	.125	.135	.15
5.	Successful wells	1	.53	.178	.352	.40
6.	Production facilities	1	.33	0	.33	.38
7.	Lease credit	1		.166	—.166	—.19
8.	Total			.610		1.6

	Net cash flow	Amount
9.	Price	×
10.	Royalty	—0.16×
11.	Operating expense	—.88
12.	Interest on working capital	—.14
13.	Tax liability	—.61
14.	Gas credit	+.61
15.	Total	.84×−1.02
16.	$1.614=(0.84×—$1.02)×1/18×7.047.	
17.	Price ×=2.013÷0.329=$6.12/bbl.	
18.	Royalty=0.16×$6.12/bbl=$0.98/bbl.	

SCHEDULE NO. 3

COST COMPUTATION (SOURCE) (REFER TO SCHEDULE NO. 1)

Line No.

1. 0.53=\$22.11/ft (1973 JAS)÷42 bbls/ft (Schedule 4).
2. 0.46=0.53 (line 1)×0.868 (Schedule 5).
3. 0.33=0.53 (line 1)×0.618 (Schedule 6).
4. 1.32=Sum of lines 1–3.
5. 0.26=\$18.93/ft (1973 JAS)÷42 bbls/ft (Schedule 4) ×0.57 (Schedule 7).
6. 0.24=0.46 (line 2)×0.5258 (Schedule 5).
7. 0.07=0.50 (lines 5 and 6)×0.1319 (Schedule 5).
8. 0.57=Sum of lines 5–7.
9. 0.88=(Schedule No. 6).
10. 0.61=(Schedule No. 6).
11. 0.14=(0.57 (line 8)×⅛×1.21 (Docket No. R–478)+0.88 (line 9)×⅛×1.48 (Docket No. R–478)+0.46 (line 2)×1.5 (opinion No. 699–H))×0.15.
12. 2.84=Line 14 minus the sum of costs.
13. 0.98=(Schedule No. 2).
14. 6.12=(Schedule No. 2).

SCHEDULE NO. 4

CRUDE OIL PRODUCTION RESERVES AND FOOTAGE (LOWER 48 STATES)

Year	Thousand barrels — Production	Thousand barrels — Reserve additions	F/P ratio	Oil well footage (thousand feet)	Productivity
(a)	(b)	(c)	(d)	(e)	(f)
1966	2,849,877	2,787,971	0.98	67,430	41
1967	3,008,666	2,873,785	.96	58,244	49
1968	3,058,042	2,396,137	.78	58,665	41
1969	3,121,193	1,986,823	.64	61,132	33
1970	3,236,170	2,889,659	.89	56,389	51
1971	3,178,158	2,272,409	.72	48,268	47
1972	3,208,627	1,504,991	.47	48,413	31
1973	3,113,078	2,057,578	.66	44,434	46
1974	2,972,847	1,941,078	.65	50,012	39
Total		20,710,431		492,987	

Note: Average productivity (1966–74)=42 barrels per feet.

Source: API—AGA and AAPG.

SCHEDULE NO. 5

ESTIMATED EXPENDITURES FOR FINDINGS AND DEVELOPING GAS AND OIL IN THE UNITED STATES, 1967–73

[Millions of dollars]

Line No.	Year	Cost of producing wells	Dry hole cost	Lease acquisition cost	Exploratory overhead	Other exploratory costs
(a)	(b)	(c)	(d)	(e)	(f)	(g)
1.	1967	1,497	802	829	206	740
2.	1968	1,583	826	1,578	204	770
3.	1969	1,723	888	1,137	210	782
4.	1970	1,706	873	714	189	728
5.	1971	1,508	864	642	206	746
6.	1972	1,807	1,006	1,722	239	766
7.	1973	2,005	1,070	3,646	293	867
8.	1967 to 1972	9,824	5,259	6,622	1,254	4,532
9.	1967 to 1973	11,829	6,329	10,268	1,547	5,399

10. Lease acquisition costs as a fraction of successful well cost=6,622÷9,824=0.6741 (1967–72); 10,268÷11,829=0.8680 (1967–73).
11. Other exploratory costs as a fraction of lease acquisition costs=4,532÷6,622=0.6844 (1967–72); 5,399÷10,268=0.5258 (1967–73).
12. Exploratory overhead as a fraction of dry hole and other exploratory costs=1,254÷9,791=0.1281 (1967–72); 1,547÷11,728=0.1319 (1967–73).

Source: "Joint Association Survey of the U.S. Oil and Gas Producing Industry," sec. I and sec. II.

SCHEDULE NO. 6

COST OF PRODUCTION FACILITIES, IMPROVED, RECOVERY PROGRAMS AND DEVELOPMENT OVERHEAD (YEAR 1973)

	Expenditure (millions)
1. Production facilities et cetera	$1, 239
2. Oil and gas well drilling	2, 009
3. Fraction equals $1,239÷$2,009=0.618.	

Source: 1973 (JAS) Joint Association Survey.

OPERATING EXPENSE (YEAR 1972)

	Expense (thousands)	Production (thousand barrels)
4. Oil leases	$1, 613, 736	1, 542, 408
5. Unit expense=105¢/bbl.		
6. Conversion to 100 percent interest=0.84×105=88¢/bbl.		

Source: Data in Docket No. R-478.

CASINGHEAD GAS CREDIT (YEAR 1974)

7. Casinghead gas production=4,208,697,000 Mcf.
8. Crude oil production=2,972,847,000 bbls.
9. Gas oil ratio=1.416 Mcf/barrel (line 7÷8).
10. Estimated gas price 55¢/Mcf.
11. Gross credit=$.78/barrel (line 9×10).
12. Net credit=$0.61/barrel (0.78 less royalty at 16 percent and production tax at 7.5 percent).

Source: API-AGA.

SCHEDULE NO. 7

ALLOCATION OF DRY HOLE FOOTAGE TO GAS WELL FOOTAGE[1], YEAR 1974

Line No.		Successful exploratory footage (1)	Percent of total (2)	Exploratory dry hole footage (3)	Allocated footage (4)	
1.	Gas	7, 665	61. 3		23, 091	(Col. (2) line 1×col. (3) line 3).
2.	Oil	4, 833	38. 7		14, 578	(Col. (2) line 2×col. (3) line 3).
3.	Total	12, 498	100. 0	37, 669	37, 669	(Line 1+2).
		Successful developmental footage (1)	Percent of total (2)	Development dry hole footage (3)	Allocated footage (4)	
4.	Gas	31, 311	40. 9		9, 661	(Col. (2) line 4×col. (3) line 6).
5.	Oil	45, 179	59. 1		13, 959	(Col. (2) line 5×col. (3) line 6).
6.	Total	76, 490	100. 0	23, 620	23, 620	(Line 4+5).

Line No.		Total Successful footage (1)	Allocated dry hole footage (2)	dry hole factor (3)	
7.	Gas	38, 975	32, 752	0. 84	(Col. (2) line 7÷col. (1) line 7).
8.	Oil	50, 012	28, 537	. 57	(Col. (2) line 8÷col. (1) line 8).
9.	Total	88, 987	61, 289		

[1] Footage in 1,000 ft and exclude Alaskan Data Source; API-AAPG.

"ADDITIONAL STAFF ANALYSIS OF THE COST OF FINDING AND PRODUCING NEW CRUDE OIL," BUREAU OF NATURAL GAS, FEDERAL POWER COMMISSION, JULY 1975

FEDERAL POWER COMMISSION,
Washington, D.C., July 21, 1975.

Hon. WARREN G. MAGNUSON,
Chairman, Committee on Commerce, U.S. Senate,
Washington, D.C.

DEAR CHAIRMAN MAGNUSON: I am pleased to forward the attached cost analyses prepared by me in response to your letter of July 15, 1975, requesting the following:

(1) An alternative to the study transmitted on June 26, using the same data and analysis but including Alaska as well as the lower 48 states. In order to assure that these computations are conservative, we would request that only one-half of the reported reserves in Alaska be used in the computation. In addition, please assume a Federal Income Tax liability equal to 10 percent of gross income on the value of crude oil produced.

(2) An estimate of the cost per million Btu's of producing new hydrocarbons, whether crude oil or natural gas. Such a computation would avoid the difficult allocation problems of joint costs between the two fuels. Please base this estimate on the five-year average of expenses, reserves additions, and production. Again, please utilize one-half of the Alaskan reserve additions in the computation and assume a Federal Income Tax liability of 10 percent of gross income from crude oil and natural gas sales.

(3) We would also request the Federal Power Commission Staff Analysis of the estimated cost of production of old domestic crude oil, which is based on 1972 data. We should also appreciate any help you can give us in trending these costs forward to reflect current 1975 costs.

The results of the foregoing analyses (1), (2) and (3) are $5.49 per barrel, $4.14 per barrel and $2.96 per barrel, respectively. A discussion of possible trending methods is provided in the attached analysis.

I will be pleased to answer any questions you have regarding the staff analysis.

Sincerely yours,

LOUIS J. ENGEL,
Supervisory Regulatory Gas Utility Specialist.

Enclosure.

ADDITIONAL STAFF ANALYSIS OF THE COST OF FINDING AND PRODUCING NEW CRUDE OIL—BUREAU OF NATURAL GAS

This additional cost analysis was prepared in response to an inquiry made by letter dated July 15, 1975, from Chairman Warren G. Magnuson on behalf of the Senate Commerce Committee. This inquiry follows an earlier inquiry made on June 20, 1975, which was answered

by letter dated June 27, 1975, with an attached cost analysis of new crude oil.

In response to Senator Magnuson's current request three cost analyses have been prepared as follows:

(A) An alternative to the study transmitted by letter of June 27, 1975, to include one-half of the reported reserves in Alaska and Federal Income Tax liability equal to 10 percent of gross income. The result of this analysis is $5.49/bbl.

(B) An estimate of the cost per million Btu's of producing new hydrocarbons including five-year averages of expenses, reserve additions, and production, one-half of Alaskan reserve additions and a Federal Income Tax liability of 10 percent of gross income. The result of this analysis is $0.74/MMBtu or $4.14/bbl.

(C) An estimate of the cost of production of old domestic crude oil based on 1972 data. The result of this analysis is $2.96/bbl including income taxes.

The cost computations related to Items (A), (B) and (C) are shown in the attached appendicies A, B & C. The cost analyses exclude production taxes.

In our discussions with the Staff of the Commerce Committee there was general agreement that the effect of Alaskan reserve additions should be considered in costing new oil because most of these reserve additions would be priced as new oil. The impact of including 50% of Alaskan reserves is significant and accounts for the substantial difference between the earlier analysis at $6.12/bbl ($6.73/bbl including the 10% tax liability) and the current analyses at $4.14/bbl and $5.49/bbl. The use of the 50% estimate is arbitrary but is believed to be reasonable in indicating the probable range of these unit cost estimates. The majority of Alaskan reserves are the result of the Prudhoe Bay discovery. This large field has not been developed and awaits a pipeline connection. Alaska and its adjacent waters is a vast unexplored area which may produce several large oil and gas fields in the future after connection to market areas is achieved.

The 10% of gross income for Federal Income Tax liability is a judgmental estimate considering the near future and the impact of the repeal of the depletion allowance. It approximates the result of applying the former depletion rate of 22% to gross income at the tax rate of 48%. Included in the $0.74/MMBtu ($4.14/bbl) lower cost estimate is a Federal Income Tax allowance of $0.07/MMBtu. If this allowance were included in the price of total hydrocarbon production, the oil and gas industry would realize additional revenue amounting to over $3 billion per year ($0.07/MMBtu times 43,535,000,000/MMBtu, 1974 production of Btu) for tax purposes. It is believed this is a reasonable estimate for the near future or until such time that formal data can be gathered to test the actual impact of the new tax laws.

The analysis in Appendix B, where costs are derived by units of heat content (Btu), does merit consideration in developing a reasonable cost range. It avoids a multitude of allocations and in effect assigns an equal amount of cost to each Btu of hydrocarbon reserves and production, where applicable. Exploration and development expenditures are related to hydrocarbon reserve additions. Production expense is properly related to hydrocarbon production since these ex-

penses are related to all age leases and wells which are on production. The resulting total cost of $0.74/MMBtu is converted to $4.14/bbl by applying the unit of 5.6MMBtu/bbl ($0.74 x 5.6).

The analysis in Appendix C reflects the cost of old oil as of year end 1972. The allocation methods employed have been adopted by this Commission in past decisions for costing old or flowing gas and have been approved by the Courts. The result of this analysis is $2.96/bbl excluding production taxes.

In our meetings with your Staff we discussed your inquiry concerning the trending of these costs beyond the period of the latest available data. This matter is complex and involves consideration of a great number of variables of which most are unknown. This trending requires the analysis of the anticipated movement of unit costs which is composed of a certain output of dollars and their relationship to reserves found or production. There is available data from the Joint Association Survey (JAS) indicating the annual amounts of exploration, development and production expenditures excluding production taxes as follows:

ESTIMATED EXPENDITURES IN THE UNITED STATES

[Millions of dollars]

Year	Exploration	Development	Production
1969	3,106	2,766	2,829
1970	2,476	2,851	3,089
1971	2,393	2,671	3,264
1972	3,672	3,093	3,299
1973	5,865	3,255	3,552

As indicated from the foregoing table the oil and gas industry has increased its output of expenditures in recent years for all three phases. Most of the increase is attributable to large bonuses paid for Federal offshore leases which are currently being explored or developed. These bonuses were also substantial in 1974. Whether these large expenditures will be made in 1975 is questionable because of the repeal of the depletion allowance. The most crucial element in any trending involves the estimation of hydrocarbon reserves which will result from current and near future exploration and development expenditures. If reserve additions do not increase it is apparent that unit costs will increase with any increase in expenditures. Another significant element, which affects exploration and development, are drilling costs. The JAS also provides these data. These costs and calculated annual changes are as follows:

DRILLING COSTS IN THE UNITED STATES

Year	Oil well drilling cost (per foot)	Annual change (percent)	Dry hole drilling cost (per foot)	Annual change (percent)
1967	$16.61		$12.87	
1968	18.63	+12	12.88	0
1969	19.28	+3	13.23	+3
1970	19.29	0	15.21	+15
1971	18.41	−5	16.02	+5
1972	20.77	+13	17.28	+8
1973	22.54	+9	19.22	+11

These data also indicate an upward trend in recent years and it is likely these costs per foot have increased significantly through the early part of 1975 due mainly to inflation. However in converting any projected costs per foot to unit costs per barrel of oil it is necessary to estimate the amount of reserves found per foot drilled. This element is difficult to estimate for either past or future periods.

If constant levels of reserve additious are assumed, the foregoing data appear to suggest an annual increase in the unit cost of new oil ranging from about 5% to 13%.

We have been unable to arrive at any conclusive method for trending the 1972 old oil cost (Appendix C) up to 1975. As we understand the pricing of old oil the ceiling price of $5.25 would not apply where secondary or tertiary recovery have been employed. If our understanding is correct on the above factors and if new oil is also that which is produced from new wells after 1972, it appears to us that the only element of cost in our computation of old oil cost that might require an adjustment is operating expense. Production expenditures (Operating expense) as published by the JAS indicate an average annual increase of about 6% for the 1969–1973 period. This, of course, is only the numerator of the unit cost but may be a reasonable indicator of projected annual changes in this unit cost.

In conclusion, it should be emphasized that there is no precise answer in estimating these unit costs because of the various assumptions which are required. It is hoped that the various cost analyses, which have been provided, will assist your committee.

LOUIS J. ENGEL,
Supervisory Regulatory Gas Utility Specialist.

APPENDIX A

SCHEDULE NO. 1

COST OF FINDING AND PRODUCING A BARREL OF NEW CRUDE OIL (TOTAL UNITED STATES)[1]

Line No.	Item description	Source	Unit (per barrel)
1.	Oil well drilling cost	Schedule 3	$0.43
2.	Lease acquisition cost	do	.37
3.	Production facilities	do	.27
4.	Subtotal		1.07
5.	Dry hole drilling cost	do	.21
6.	Other exploration cost	do	.19
7.	Exploration overhead	do	.05
8.	Subtotal		.45
9.	Operating expense	do	.88
10.	Casinghead gas credit	do	(.61)
11.	Return on working capital	do	.12
12.	Return on investment	do	2.28
13.	Royalty at 16 percent	Schedule 2	.80
14.	Subtotal	do	4.99
15.	Total, including income tax at 10 percent of gross income		5.49

[1] Includes Alaskan data to the extent that 50 percent of Alaskan oil additions were included in the productivity estimate.

SCHEDULE NO. 2

COMPUTATION OF PRICE BY THE DCF METHOD

Preproduction costs	Year	Value	Tax credit	Net investment	15 percent present value
1. Other exploration	3	0.19	$0.087	0.103	$0.157
2. Exploration overhead	3	.05	.023	.027	.041
3. Lease acquisition	2	.37	0	.37	.489
4. Dry holes	1	.21	.101	.109	.125
5. Successful wells	1	.43	.144	.286	.329
6. Production facilities	1	.27	0	.27	.311
7. Lease credit	1		.133	−.133	−.153
8. Total		1.52	.488		1.299

Net cash flow	Amount
9. Price	$\times$
10. Royalty	$-0.16\times$
11. Operating expense	−.88
12. Interest on working capital	−.12
13. Tax liability	−.448
14. Gas credit	+.61
15. Total	$.84\times-0.878$

16. $1.299=(0.84\times-\$0.878)\times1/18\times7.047$.[1]
17. Price $X=1.643\div0.329=\$4.99$/bbl.
18. Royalty $=0.16\times\$4.99/\text{bbl}=\$0.80$/bbl.

[1] $$7.047=\frac{1.15-\frac{(1)}{(1.15)^{17}}}{0.15}.$$

SCHEDULE NO. 3

COST COMPUTATION (SOURCE) (REFER TO SCHEDULE NO. 1)

Line No.

1. 0.43 = $22.11/ft (1973 JAS) ÷ 52 bbls/ft.
2. 0.37 = 0.43 (line 1) × 0.868 (Schedule 5).
3. 0.27 = 0.43 (line 1) × 0.168 (Schedule 6).
4. 1.07 — Sum of lines 1-3.
5. 0.21 = $18.93/ft (1973 JAS) ÷ 52 bbls/ft (Schedule 4) × 0.57 (Schedule 7).
6. 0.19 = 0.37 (line 2) × 0.5258 (Schedule 5).
7. 0.05 = 0.04 (lines 5 and 6) × 0.1319 (Schedule 5).
8. 0.45 = Sum of lines 5-7.
9. 0.88 = (Schedule No. 6).
10. 0.61 = (Schedule No. 6).
11. 0.12 = (0.45 (line 8) × 1/8 × 1.21 (Docket No. R-478) + 0.88 (line 9) × 1/8 × 1.48 (Docket No. R-478) + 0.37 (line 2) × 1.5 (Opinion No. 699-H)) × 0.15.
12. 2.28 = Line 14 minus the sum of costs.
13. 0.80 = (Schedule No. 2).
14. 4.99 = (Schedule No. 2).

SCHEDULE NO. 4

CRUDE OIL PRODUCTION RESERVES AND FOOTAGE

Year	Production (thousand barrels)	Reserve additions (thousand barrels)	F/P ratio	Oil well footage (thousand feet)	Productivity
(a)	(b)	(c)	(d)	(e)	(f)
1966	2,849,877	2,787,971	0.98	67,430	41
1967	3,008,666	2,873,785	.96	58,244	49
1968	3,058,042	2,396,137	.78	58,665	41
1969	3,121,193	1,986,823	.64	61,132	33
1970	3,236,710	2,879,659	.89	56,389	51
1971	3,178,158	2,272,409	.72	48,268	47
1972	3,208,627	1,504,991	.47	48,413	31
1973	3,113,078	2,057,578	.66	44,434	46
1974	2,972,847	1,941,078	.65	50,012	39
Total		20,710,431		492,987	

Note: Average productivity (1966–74) equals 42 bbl/ft, excluding Alaska; 52 bbl/ft, includes 50 percent of Alaskan reserve additions and footage (50 percent of 10,500,000,000 bbl of crude and 3,200,000 ft of drilling footage).

Source: API—AGA and AAPG.

SCHEDULE NO. 5

ESTIMATED EXPENDITURES FOR FINDINGS AND DEVELOPING GAS AND OIL IN THE UNITED STATES, 1967-73

[In millions of dollars]

Line No. (a)	Year (b)	Cost of producing wells (c)	Dry hole cost (d)	Lease acquisition cost (e)	Exploratory overhead (f)	Other exploratory costs (g)
1.	1967	1,497	802	829	206	740
2.	1968	1,583	626	1,578	204	770
3.	1969	1,723	888	1,137	210	782
4.	1970	1,706	873	714	189	728
5.	1971	1,508	864	642	206	746
6.	1972	1,807	1,006	1,722	239	766
7.	1973	2,005	1,070	3,646	293	867
8.	1967-72	9,824	5,259	6,622	1,254	4,532
9.	1967-73	11,829	6,329	10,268	1,547	5,399

10. Lease acquisition costs as a fraction of successful well cost=6,622÷9,824=0.6741 (1967-72); 10,268÷11,829=0.8680 (1967-73).
11. Other exploratory costs as a fraction of lease acquisition costs=4,532÷6,622=0.6844 (1967-72); 5,399÷10,268=0.5258 (1967-73).
12. Exploratory overhead as a fraction of dry hole and other exploratory costs=1,254÷9,791=0.1281 (1967-72); 1,547÷11,728=0.1319 (1967-73).

Source: "Joint Association Survey of the U.S. Oil and Gas Producing Industry," sec. I and sec. II.

SCHEDULE NO. 6

COST OF PRODUCTION FACILITIES, IMPROVED, RECOVERY PROGRAMS AND DEVELOPMENT OVERHEAD (YEAR 1973)

	Expenditure (millions)
1. Production facilities, etc	$1,239
2. Oil and gas well drilling	2,009
3. Fraction equals $1,239÷$2,009=0.618.	

Source: 1973 (JAS) Joint Association Survey.

OPERATING EXPENSE (YEAR 1972)

	Expense (thousands)	Production (thousand barrels)
4. Oil leases	$1,613,736	1,542,408
5. Unit expense=105¢/bbl.		
6. Conversion to 100 percent interest=0.84×105=88¢/bbl.		

Source: Data in Docket No. R-478.

CASINGHEAD GAS CREDIT (YEAR 1974)

7. Casinghead gas production=4,028,697,000 Mcf.
8. Crude oil production=2,972,847,000 bbls.
9. Gas oil ratio=1.416 Mcf/bbl (line 7÷8).
10. Estimated gas price 55 /Mcf.
11. Gross credit=$.78/bbl (line 9×10).
12. Net credit=$0.61/bbl (0.78 less royalty at 16 percent and production tax at 7.5 percent).

Source: API—AGA.

SCHEDULE NO. 7

ALLOCATION OF DRY HOLE FOOTAGE TO GAS WELL FOOTAGE,[1] YEAR 1974

Line No.		Successful exploratory footage (1)	Percent of total (2)	Exploratory dry hole footage (3)	Allocated footage (4)	
1.	Gas	7,665	61.3		23,091	(Col. (2) line 1×col. (3) line 3.)
2.	Oil	4,833	38.7		14,578	(Col. (2) line 2×Col. (3) line 3.)
3.	Total	12,498	100.0	37,669	37,669	(Line 1+2.)
		Successful developmental footage (1)	Percent of total (2)	Developmental dry hole footage (3)	Allocated footage (4)	
4.	Gas	31,311	40.9		9,661	(Col. (2) line 4×col. (3) line 6.)
5.	Oil	45,179	59.1		13,959	(Col. (2) line 5×col. (3) line 6.)
6.	Total	76,490	100.0	23,620	23,620	(Line 4+5.)

Line No.		Total successful footage (1)	Allocated dry hole footage (2)	Dry hole factor (3)	
7.	Gas	38,975	32,752	0.84	(Col. (2) line 7÷col. (1) line 7.)
8.	Oil	50,012	28,537	.57	(Col. (2) line 8÷col. (1) line 8.)
9.	Total	88,987	61,289		

[1] Footage in 1,000 ft and exclude Alaskan data.

Source: API–AAPG.

APPENDIX B

SCHEDULE NO. 1

COST OF FINDING AND PRODUCING HYDRACARBONS ON A BTU BASIS, TOTAL UNITED STATES[1]

[Expenditures in millions]

Line No. (a)	Item description (b)	Expenditures (1969–73) (c)	Annual average expenditures (d)	Heat content (T Btu) (e)	Unit cost per million (f)
1	Exploration	$17,512	$3,502	31,246	$0.
2	Development	14,636	2,927	31,246	.
3	Subtotal	32,148	6,429	31,246	.20
4	Production	16,033	3,207	43,535	.07
5	Return allowance at 15 percent				.29
6	Royalty at 16 percent				.11
7	Subtotal				.67
8	Income taxes at 10 percent of gross revenue				.07
9	Total				.74
10	Conversion to dollars per barrel at 5,600,000 Btu/barrel				4.14

[1] Includes Alaskan data to the extent that 50 percent of oil and gas reserve additions were included in estimating the verage annual Btu.

Sources: Col. (c): Joint Association Survey (JAS); col. (d): col. (c)÷5; col. (e): schedule No. 3; col. (f): lines 1, 2, and 4, ol. (d)÷col. (e); col. (f): lines 5, 6, and 7, schedule No. 2; col. (f): line 8, line 7×10 percent.

SCHEDULE NO. 2

COMPUTATION OF PRICE BY THE DCF METHOD

Line No.

1. Investment = $0.20/MM Btu.
2. Tax credit = $0.06/MM Btu.
3. Net investment = $0.14/MM Btu.
4. Present value of net investment = $0.17/MM Btu.
   Price computation:
5. Price = x.
6. Price less royalty = 0.84x.
7. Production expense = 0.07.
8. Tax liability = 0.06.
9. Cash flow = 0.84x + 0.07 + 0.06.
   Present value of net investment equals the present value of the net cash flow.
10. $0.17 = (0.8x - 0.13) \times 1/18 \times 7.047$.[1]
11. x = $0.67/MM Btu.
12. Royalty = $0.11 = 0.67 \times 0.16$.

[1] $7.047 = \dfrac{1.15 - \left(\frac{1}{1.15}\right)^{17}}{0.15}$

Sources: Line 1 and 7: schedule No. 1; line 2: 0.20× 67 percent (expensed)×48 percent (tax rate); line 3: line 1 minus line 2; line 4: line 3 times 1.2332 (interest at 1½ yr); line) line 8: line 2.

Schedule No. 3

Hydrocarbon reserve additions, production and related Btu content

Reserve additions (1970–74):		
1. Crude oil (total United States)	Million barrels	20,703,902
2. Lease and plant condensate (total United States)	do	370,950
3. Crude and condensate (total United States)	do	21,074,852
4. 50 percent of Alaskan crude additions	do	5,019,094
5. Remaining United States	do	16,055,758
6. Unit heat content	Million Btu per barrel	5.6
7. Total Btu (1970–74),	trillion Btu	89,912
8. Annual average	do	17,982
9. Total gas liquids	Million barrels	1,922,392
10. Plant extracted liquids	do	1,551,442
11. Total dry gas	Billion cubic feet	72,160
12. Total wet gas	do	73,711
13. 50% of Alaskan gas	do	13,418
14. Remaining United States	do	60,293
15. Unit heat content	Million Btu per thousand cubic feet	1.1
16. Total Btu (1970–74)	trillion Btu	66,322
17. Annual average	do	13,264
18. Total average annual hydrocarbons	do	31,246
Production (1970–74):		
19. Total wet gas	trillion Btu	122,448
20. Crude and condensate	do	95,229
21. Total hydrocarbons	do	217,677
22. Annual average	do	43,535

Sources: AGA, API and U.S. Bureau of Mines.

Line 2 was calculated using the ratio of 10 bbls of condensate per million cubic feet of nonassociated reserve additions.

Line 10 equals line 9 minus line 2.

Line 12 equals line 10 plus line 11 using the equivalent of 1 bbl=1 Mcf.

Appendix C

Schedule No. 1

Cost of flowing oil [1]

Production cost: [2]	
1. Cash expense (per barrel)	$1.02
2. D.D. & A	0.48
3. Return	0.74
Total	2.24

Exploration and development[3] allowance (E. & D.):

4. Expense	0.34
5. Return	0.11
6. Total	0.45
7. Total, production and E. & D	2.69
8. FIT computed as 10 percent of line 7	0.27
9. Total (per barrel)	2.96

[1] Cost of flowing oil is estimated on a basis comparable to the cost of flowing gas, under past Commission approved methods, in Commission Notice Issuing Staff Rate Recommendation and Prescribing Procedures, issued September 12, 1974, in Docket No. R-478. (See Notice Appendix B, Summary, Schedule No. 1–A, Column (e)). Method further combines operations of Independent Producers, Pipeline Affiliates, and Pipeline Producers which were reported in subject docket in year 1972 for the Lower 48.

[2] Production costs are based on current year 1972 operations on leases producing essentially oil or leases producing oil and casinghead gas. Leases producing both oil and gas-well gas (combination leases) were excluded from study because of the complexity in allocation procedures. Allocation of joint product oil and casinghead gas costs was made on the basis of relative costs, i.e., through consideration of what it would cost to produce the products singly as measured by the cost of separate product gas-well gas and single product oil.

[3] E & D costs are based on current expenditures for essentitally unsuccessful costs. E & D costs are first assigned, and the remainder allocated, on the basis of the respondents reported intent as between gas reservoir and oil reservoir operations. Costs for oil reservoir operations were then allocated between oil and gas current production, as measured by Btu content, after the oil Btu's had first been modified by a multiple of 2.5. The resulting with E & D cost for oil was then imputed to production of oil on the subject lease types.

COST OF CRUDE OIL ON OIL ONLY AND OIL CASINGHEAD GAS LEASES USING RELATIVE COST ALLOCATION FOR PRODUCTION COSTS AND MODIFIED BTU ALLOCATION FOR EXPLORATION AND DEVELOPMENT (E AND D) COSTS—ALL COMPANIES (1972 DATA)

			Single, Product Cost—$/Bbl or $/Mcf			Relative Costs			Cost Allocations		
Line No.	Production Costs (a)	Bbl or Mcf (b)	Cash Expense (c)	D.D. & A. (d)	Gross Inv. (e)	Cash Exp. (f)	D.D. & A. (g)	Gross Inv. (h)	Cash Exp. (i)	D.D. & A. (j)	Return (k)
	Oil Only Leases:										
1	Oil	264, 164, 000	1. 5542	0. 6237	14. 7978	410. 563, 689	164, 759, 087	3, 909, 046, 039	414, 029, 212	166, 783, 602	251, 486, 012
2	Casinghead Gas	6, 536, 000	0. 03188	0. 03657	0. 77449	208, 368	239, 022	5, 062, 067	210, 127	241, 961	325, 665
3	Total					410, 772, 057	164, 998, 109	3, 914, 108, 106	414, 239, 339	167, 025, 563	251, 811, 677
	Oil Casinghead Gas Leases:										
4	Oil	1, 279, 461, 000	1. 5542	0. 6237	14. 7978	1, 988, 538, 286	797, 999, 826	18, 933, 207, 986	1, 168, 776, 998	616, 599, 654	891, 564, 580
5	Casinghead Gas	1, 772, 858, 000	0. 03188	0. 03657	0. 77449	56, 518, 713	64, 833, 417	1, 373, 060, 792	33, 219, 260	50, 095, 578	64, 657, 420
6	Total					2, 045, 056, 999	862, 833, 243	20, 306, 268, 778	1, 201, 996, 258	666, 695, 232	956, 222, 000

Exploration and Development (E and D Costs):

7 Joint E and D Costs (Oil Reservoirs) × Oil Btu × 2.5/(Oil Btu×2.5 + Gas Btu).

8 $1,048,658,752×(11,657×2.5)/(11,657×2.5+3,874)=$925,600,075 $925,600,075/2,050,244,000 bbl=$0.45/bbl.

Summary (Relative Cost and Modified Btu Allocation):

Line			
9	Cash Expense	$414, 029, 212	$2. 24/bbl Production Cost.
10		1, 168, 776, 998	0. 45/bbl Exploration and Development.
11	Depreciation, Depletion and Amortization	116, 783, 602	$2. 69/bbl. Excluding Production Tax, Income Tax.
12		616, 599, 654	
13	Return	251, 486, 012	
14		891, 564, 580	
15	Total	$3, 459, 240, 058/1,543,625,000=$2.24/bbl, Production Cost.	

U.S. SENATE,
COMMITTEE ON COMMERCE.
Washington, D.C., July 15, 1975.

Hon. JOHN N. NASSIKAS,
Chairman, Federal Power Commission,
Washington, D.C.

DEAR MR. CHAIRMAN: Thank you very much for your June 26 letter transmitting a staff computation of the cost of new domestic crude oil in 1974, based on nationwide costs and drilling comparable to your natural gas costing techniques.

With your concurrence, members of the staff of the Senate Commerce Committee met with members of your staff to obtain a better understanding of the methodologies used. The initial staff analysis, of course, was preliminary, and based on a single set of assumptions. In light of the importance of this matter, the staffs agreed that other approaches to crude oil prices would be useful to develop. Accordingly, we request the following cost analysis:

(1) An alternative to the study transmitted on June 26, using the same data and analysis but including Alaska as well as the lower 48 states. In order to assure that these computations are conservative, we would request that only one-half of the reported reserves in Alaska be used in the computation. In addition, please assume a Federal Income Tax liability equal to 10 percent of gross income on the value of crude oil produced.

(2) An estimate of the cost per million Btu's of producing new hydrocarbons, whether crude oil or natural gas. Such a computation would avoid the difficult allocation problems of joint costs between the two fuels. Please base this estimate on the five-year average of expenses, reserves additions, and production. Again, please utilize one-half of the Alaskan reserve additions in the computation and assume a Federal Income Tax liability of 10 percent of gross income from crude oil and natural gas sales.

(3) We would also request the Federal Power Commission Staff Analysis of the estimated cost of production of old domestic crude oil, which is based on 1972 data. We should also appreciate any help you can give us in trending these costs forward to reflect current 1975 costs.

These further analyses would provide the Committee with a range of new domestic crude oil costs under various assumptions. We would hope that this staff analysis could be completed by *Monday, July 21*, since we expect the issue of crude oil pricing to be debated on the floor of the Senate soon.

Thank you very much for your assistance.

Sincerely,

WARREN G. MAGNUSON, *Chairman.*

CHAPTERS I AND II OF *ENERGY AND THE ECONOMY*, A STAFF REPORT OF THE TASK FORCE ON ENERGY OF THE COMMITTEE ON THE BUDGET, UNITED STATES SENATE, OCTOBER, 1975

94th Congress }
1st Session }

COMMITTEE PRINT

ENERGY AND THE ECONOMY

STAFF REPORT

OF THE

TASK FORCE ON ENERGY

OF THE

COMMITTEE ON THE BUDGET
UNITED STATES SENATE

OCTOBER 23, 1975

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LETTER OF TRANSMITTAL

Senator EDMUND S. MUSKIE,
Chairman, Senate Budget Committee,
Washington, D.C.

DEAR MR. CHAIRMAN: Attached is the staff report for the Task Force on Energy.

This analysis, together with the other information derived from the public hearings, conducted in July, provides the background for the previously submitted report of the Task Force on Energy. The report makes clear that both macroeconomic and energy policies must be integrated. It also indicates that national goals must be cognizant of international realities. Achievement of both energy independence and economic recovery points up the need for a comprehensive approach regarding energy prices.

Several energy price policy options were considered in this analysis. Central to all of the options is the concept that prices for both oil and natural gas must be considered simultaneously.

The results indicate that the balance between energy and economic goals can best be met with a program that includes phased decontrol, a price ceiling on new oil (with exclusions), a price ceiling on new natural gas (with exclusions), and elimination of the tariff on oil.

Along with thanking the Task Force staff, I also want to express special appreciation to the following members of the Committee staff without whose efforts this report would not have been possible: Arnold Packer, Dennis Sachs, Paul Shechtman, Martin Asher, and Donald Nichols for their role in preparing the report; and Carole Johnson, Hanno Hinsch, Mary McGuire, and Renee McKinney who assisted with the research and editing.

The views expressed in this report do not necessarily represent the views of the Members of the Task Force.

Sincerely,

FRANK E. MOSS.
Chairman, Task Force on Energy.

CONTENTS

Chapter I

THE CHOICES*

A. Purpose of the Report

The task before Congress in the energy field is to pass legislation that will:

—Promote a prompt recovery from the recession, without further aggravating inflation.

—Foster greater energy self-sufficiency.

Either task taken separately and with unlimited time for analysis and deliberation would present a significant challenge. But the tasks cannot be addressed separately and the time remaining for deliberation is short. Furthermore, while some decisions can be made that will move the United States to both objectives, other decisions would be in conflict.

For example, a dramatic rollback of domestic oil prices would have welcome anti-inflation effects and it would reduce unemployment at least in the short run. But it would discourage domestic production and exploration and would increase reliance on foreign sources of oil, with unfortunate consequences in the longer run.

CONFLICTS MUST BE RESOLVED

These basic conflicts must be resolved or at least clearly identified and marked for early action this autumn when Congress adopts a Second Concurrent Resolution on the Budget for Fiscal 1976. The resolution will place a binding limit on overall spending, establish a floor under revenues, and determine the size of the deficit. The resolution will not be developed in a vacuum. It will have to reflect the best estimate of the behavior of the U.S. economy during the fiscal year. And the economy, in turn, will depend on the price and availability of energy.

Most economists doubt that the economic goals of the First Concurrent Resolution—the unemployment rates, the inflation rates and the levels of economic activity—can be achieved if energy prices were immediately decontrolled and if the OPEC countries were to carry out their announced intention to increase the price of crude oil by $1 per barrel. With another set of policies, both in the United States and abroad, the goals might be reached.

Because of this relationship between energy and Federal budget policy, the Senate Budget Committee has established an Energy Task Force. The Task Force's objective is to spell out the broad alternatives open to the Budget Committee and to Congress and to assess the consequences of pursuing each course of action.

*For limitations in the analysis, see pages 7–9, Chapter I.

2

JUDGMENTS REQUIRED

The formulation of energy policy requires judgments about politics, economics and technology not only in the United States but abroad. In many cases, the judgments must be made without complete information and often there are important differences of views among experts. There are basic gaps in the data on energy supply, for example, and the estimates of the level of energy technology that can be achieved in the next 5 or 10 years are at best educated guesses.

Furthermore, Congress must choose policies that fit two widely different planning horizons. Policies which are adopted in the months ahead must take into account the long lead times associated with energy developments. At the same time, the Congress must bear in mind the immediate problems such as new OPEC price increases and shortages of natural gas that may affect the economy this winter.

Federal energy policy must be firm enough to encourage private investment yet flexible enough to accommodate contingencies.

Finally, energy policy must be formed in the context of conflicting views of self-interest among the countries of the industrial world, oil exporters and developing nations.

WIDE AGREEMENT

In order to reduce this complexity to something approaching manageable terms, the Task Force staff has drawn on expert testimony, on recent studies, and on its own analysis to produce this staff report. This staff report notes areas of wide agreement on the nature of the energy problem. But more important it reduces areas of disagreement to broad but fundamental choices and presents analysis that illuminates the principal effects of these choices on energy prices and the economy and on progress toward greater energy self-sufficiency.

B. The Energy Problem

The economic disruption which the United States and other industrial nations have experienced over the last year began with increases in oil prices; oil price increases remain an important threat to the economies of all industrial nations.

It is almost 2 years since OPEC imposed its oil embargo in 1973. During these 2 years, the price of OPEC oil has increased five-fold. Simultaneously, the industrial world has experienced its most violent inflation in this century and its most serious recession since the Great Depression of the 1930's. While the energy situation was not the only cause of the increase in the general price level and unemployment, it is clear that the increase in oil prices played a major role in the economic disruption.

The OPEC cartel is unlikely to dissolve soon in a competitive economic war; at least U.S. policy cannot be based on that possibility. The cartel has indicated it will continue to ask a higher price for its oil. There is virtually no chance that pre-1973 oil prices can be reestablished. If oil prices decrease at all, it is unlikely to happen for several years. The best the United States and other oil importing countries may be able to do is to keep current OPEC prices from rising further and to accommodate themselves to these prices with as little disruption as possible.

3

DEPENDENCE ON OPEC OIL

The dependence of the industrialized world on OPEC oil, which began in the 1950's, will persist throughout the 1970's and into the 1980's. That dependence will expose the industrialized world not only to OPEC price pressure but to the prospect of attempts at foreign policy manipulation with new embargoes as one policy weapon.

The United States can hold down its needs for imported oil by increasing domestic production, accelerating its nuclear fission and other alternate source programs and implementing more stringent conservation measures. No matter what policies the United States pursues in the short run, there is no prospect for altering the fundamental dependence of the industrial world on OPEC oil until the 1980's. Nonetheless, if energy-dependency is to be reduced in the next decade, the United States must begin immediately to develop new technologies for using and producing energy. *Until U.S. policies begin to pay off in greater control over price and supply, the OPEC countries will be running large trade surpluses and accumulating petrodollars.*

C. Policy Strategies

Congress will make a number of decisions with respect to energy policy over the next few months. Each of those decisions will directly affect consumers and producers and, in turn, the U.S. economy. Among the decisions Congress will address are:

—Should the price of "old" oil be decontrolled and, if so, in what way and how fast?
—Should the price of "new" oil be controlled and, if so, at what price?
—Should new natural gas prices be deregulated or simply increased by regulation and, if so, what new prices would be set for interstate and intrastate gas?
—Should the price of natural gas already flowing be allowed to rise from the current price?
—Should tariffs be used to further increase energy prices?

In order to provide information to the Task Force that would evaluate the choices the staff report has examined four energy policy alternatives. Although none of the alternatives may correspond exactly to current proposals, two alternatives are similar to policies that have been proposed by the administration. Two other alternatives have been designed by the staff to illustrate important effects that would ensue from a policy approach significantly different from the first two.

1. Immediate Decontrol

The first alternative is one in which oil and natural gas price controls are eliminated immediately. The rationale for this alternative is that, given the uncertainty and politics of the energy situation, market pricing will best allow adjustment to change and will balance the costs and benefits of energy production and consumption.

PRINCIPAL ELEMENTS

The principal elements of this alternative are:
—immediate decontrol of "old" oil prices;

—immediate deregulation of "new" gas in interstate markets; and
—elimination of the $2.00 oil tariff.

An "immediate oil decontrol" alternative, with a tariff, had originally been advocated by the administration. Recently, however, the administration has indicated willingness to consider a 39-month phase-out of oil price controls.

2. 39-Month Phaseout, $11.50 Oil, Natural Gas Deregulation

The second alternative is one in which all oil prices are controlled for 39 months, and new natural gas prices are immediately deregulated. This alternative recognizes the threat to price stability and economic recovery inherent in immediate oil price decontrol and would moderate that threat by allowing oil prices to increase less rapidly over a period of 39 months. This alternative also reflects the view that rising prices are necessary to provide incentive for development of domestic energy sources.

PRINCIPAL ELEMENTS

The principal elements of this alternative are:
—imposition of a ceiling price on new oil for 39 months, with the ceiling price set initially at $11.50 per barrel and increasing at the rate of $.05 per month for 39 months;
—redefinition of "old" oil so that by the end of 39 months all domestic oil is subject to a single ceiling price;
—deregulation of new natural gas; and
—elimination of the $2.00 oil tariff.

3. 66-Month Phaseout, $9.00 Oil, $1.30 Natural Gas

The third alternative is one in which prices for both oil and natural gas would be controlled for 66 months. This alternative places a high premium on preventing energy price shocks and reflects the view that adequate incentives for energy conservation and production can be provided even with price controls on both oil and natural gas which allow relatively modest price increases over a period of 66 months.

PRINCIPAL ELEMENTS

The principal elements of this alternative are:
—imposition of a ceiling price on new oil for 66 months, with the ceiling price set initially at $9.00 per barrel and increasing at 5 cents per month for 66 months;
—redefinition of "old" oil so that by the end of 66 months all domestic oil is subject to a single ceiling price;
—extension of controls to natural gas in intrastate markets with a ceiling price on new gas set initially at $1.30 per Mcf and increasing at 1 cent per month for 66 months; and
—elimination of the oil tariff.

4. 66-Month Phaseout, $7.50 Oil, $1.00 Natural Gas

The fourth alternative is similar to the third except that the ceiling prices for oil and natural gas are set initially at $7.50 per barrel and $1.00 per Mcf respectively.

D. Criteria for Choosing

The choice among alternative energy policies should depend primarily on how well each would satisfy the two objectives stated on the first page; on which alternative strikes the best balance among the following goals for the economy and energy independence:

(1) A prompt recovery from the current recession, given the likely restraints on fiscal and monetary policies;

(2) Retention of the gains already achieved on inflation;

(3) Growing independence of OPEC decisions in the sense that the United States could withstand higher OPEC oil prices or an Arab embargo without undue economic hardship; and

(4) Influence over OPEC to stabilize or even reduce the world price of oil.

Obviously, these goals are related and progress toward one will have important effects on the other goals. For example, if the United States could eliminate its oil imports, thereby becoming independent of OPEC decisions, it would at the same time discourage further oil price increases by shrinking the OPEC market.

Recovery, inflation and energy independence are related. The fear of reigniting inflation may restrict the speed at which both economic recovery and energy independence are pursued. And economic recovery itself will increase energy consumption and oil imports in the short-run at least.

ALTERNATIVES EXAMINED

The following chapters will examine each of the alternatives quantitatively in terms of these goals and related issues. How much will each alternative add to domestic energy production or reduce U.S. energy consumption, thereby diminishing U.S. oil imports? What are the inflationary consequences of each choice over the remainder of this decade? How much will each alternative add to unemployment if targets for the deficit and the growth in the money supply remain unaltered or, equivalently, how much larger must the deficit and money stock be to leave the unemployment rate unaltered irrespective of the choice on energy? What are the deficit and monetary policy implications for fiscal year 1976 and 1977 of each alternative, assuming a target unemployment rate of, say, 6.5 percent is sought for the end of 1977.

E. Summary of Analysis and Major Conclusions

The staff analysis indicates that under all the alternatives, except the 66-month phaseout with $7.50 oil and $1.00, natural gas energy prices would increase over the next year. In the subsequent year, 1976:4 to 1977:4, energy prices would increase under all four alternatives.

The energy price increases associated with the alternatives will add to inflation and, by reducing consumer purchasing power, will increase unemployment. The inflation and unemployment effects are most adverse in the immediate decontrol alternative, and least adverse in the 66-month phaseout with $7.50 cil and $1.00 natural gas. The unemployment effects can be further moderated by fiscal and monetary policies. (In addition, it should be noted that no consideration was given to any unemployment or inflation which might result from

TABLE I.—*Energy prices—Percent change under alternative decontrol policies*

	Policy options			
	Immediate	39-mo. $11.50 oil $1.80 gas	66-mo. $9.00 oil $1.30 gas	66-mo. $7.50 oil $1.00 gas
75:3 to 76:4	36. 6	14. 6	2. 1	−2. 9
76:4 to 77:4	20. 1	24. 3	16. 5	14. 0

shortages or allocations of energy should these occur under the 66-month or even the 39-month alternatives.)

Each alternative but the 66-month phaseout with $7.50 oil and $1.00 natural gas provides the certainty of high enough prices for new oil and gas to provide adequate incentive for new exploration development. The 66-month phaseout with $9.00 oil and $1.30 natural gas would allow a rate of return on investment of between 12.3 percent and 14 percent depending on cost assumptions. It should be noted that the average rate of return in the oil and gas industry is almost 12 percent over the last 10 years. However, with $7.50 oil and $1.00 natural gas the rate of return would be about 8 percent, too low to provide adequate incentive for new exploration and development.

TABLE II.—*Inflation and unemployment rates—Percent increases under alternative decontrol policies*

	Policy options			
	Immediate	39-mo. $11.50 oil $1.80 gas	66-mo. $9.00 oil $1.30 gas	66-mo. $7.50 oil $1.00 gas
Inflation rate:				
75:3 to 76:4	2. 9	1. 2	0. 3	−0. 1
76:4 to 77:4	1. 8	1. 9	1. 1	. 9
Unemployment rate:*				
75:3 to 76:4	. 9	. 4	. 1	0
76:4 to 77:4	. 5	. 6	. 3	. 3

*Assuming no fiscal and monetary effects.

NEAR-TERM INCREASES

Oil imports increase above current levels under all of the alternatives in the near term, 1975:3 to 1977:4. By 1980:4, however, imports are diminishing as domestic production responds to price incentives in all of the alternatives except the 66-month phaseout with $7.50 oil and $1.00 natural gas.

The staff analysis indicates that it may be impossible to mitigate the inflationary consequences of higher energy prices. Therefore, only the 66-month phaseout with $9.00 oil and $1.30 natural gas could provide the required investment incentives without jeopardizing the inflation rate targets assumed in the First Concurrent Resolution.

TABLE. III.—*Oil import levels under alternative decontrol policies*

	Policy options			
	Immediate	39-mo. $11.50 oil $1.80 gas	66-mo. $9.00 oil $1.30 gas	66-mo. $7.50 oil $1.00 gas
1975:3	6. 2	6. 2	6. 2	6. 2
1977:4	7. 3	7. 7	7. 9	8. 6
1980:4	5. 2	5. 2	7. 0	9. 4

The 39-month alternative would provide a higher rate of return with somewhat more inflation.

ENERGY SHOCK DETRIMENTAL

Although it may be possible to offset the reduction in purchasing power of higher energy prices, a full fiscal and monetary offset will be difficult to achieve if the economy experiences a large energy shock. Immediate decontrol would likely entail abandonment of the unemployment targets set forth in the First Concurrent Resolution.

Limitations to Analysis

Policymakers will have to make judgments concerning economics and technology that are subject to a host of uncertainties. This report is intended to help in those judgments. But, it must be remembered that this analysis depends on the underlying assumptions. Therefore, the important technical and conceptual limitations to this study should be stated explicitly. Some of the following considerations could be quantified with substantial further work—others cannot be.

BTU EQUIVALENT

(1) To facilitate calculations of overall price increases this report has assumed that all fuels tend (possibly with some lag) toward the Btu equivalent price of oil unless the prices are controlled. As mentioned in the report, this tendency is subject to (*a*) the ability and suitability of substituting one fuel for another, (*b*) the extent to which long-term contracts and State regulations are binding, and (c) the competitiveness of each energy industry. The result is that it is difficult to determine in this historically unique environment the actual price movements which will follow any policy alteration. The price of any fuel may be higher or lower than the Btu equivalent price.

ECONOMIC CONSEQUENCES

(2) The eventual economic consequences of increased fuel prices are dependent upon the manner in which the recipients of the revenue increases (fuel producing countries and domestic companies) spend their revenues. Several factors may be mentioned as possible offsets to the drop in consumption and investment occasioned by higher energy prices. To the extent that increased revenues result in inducing new net investment and exports, domestic employment is stimulated.

Likewise, the effect of OPEC and third country purchases of financial assets would have a mitigating effect upon interest rates, and hence would be beneficial to investment. State and local governments will receive increased revenues from severance taxes and royalties and any increase in their expenditures caused by this revenue flow will also help offset the depressing effects upon the economy. Again, though some attempt is made to account for these offsets, the prediction of their total impact is likely subject to considerable error.

DEPRESSING EFFECT

(3) OPEC price increases, programs of decontrol and sympathetic fuel price movements will have a depressing effect upon economic activity unless they are offset by the considerations enumerated above. This report suggests any recessionary effect that does remain can be cushioned by offsetting monetary and fiscal policy. It should be noted that the effectiveness of these offsets depends upon the degree to which the drain on consumer purchasing power is equivalent to a "tax" as it is suggested in chapter III. It is, in fact, equivalent only if (*a*) relative prices of some commodities on the economy do not adjust downward in response to energy price increases, (*b*) proceeds from higher prices are not respent by domestic producers or OPEC countries, (*c*) the quantity of fuels purchased are not responsive to price ("price inelastic"), and (*d*) the average rate at which currency changes hands (velocity) does not increase to support the higher price level. Otherwise, the extent of monetary and fiscal offset must be adjusted downward from a strict dollar-for-dollar offset. This report does make some adjustment but may still overstate the degree required. That is, not all changes in relative prices can be, or should be, offset by monetary and/or fiscal policy.

WHARTON ECONOMETRIC MODEL

(4) The Wharton Econometric Model, which is used to allocate the total inflationary effects of energy price increases and the monetary and fiscal actions called for by the potential recessionary impact may be the best simulative device available. However, the model is based upon historical relationships which were never subjected to our present energy environment. Consequently, the results should be approached with caution.

Likewise, it must be remembered that the relationships expressed in the model are necessarily limited. For example, the simulations do not account for the economic costs of natural gas shortages. The model seems to predict the unemployment effects of decontrol but ignores the unemployment effects, particularly in the case of natural gas, of not having decontrol.

Secondly, the simulations do not account for extra costs associated with natural gas curtailments, such as, the added costs for conversion from natural gas to alternative fuels and the added per unit costs of transportation associated with curtailments. Estimates show these costs for the Nation to run into billions of dollars.

PSYCHOLOGICAL ADVANTAGES

Third, the simulations ignore much longer-run supply effects in the energy industry. There are major economic, social, national

security and market psychology advantages of price certainty and price allocation. In this context, one must ask the question: What costs are associated with doing nothing? How much investment has not taken place because of uncertainty in the energy industry? How much unemployment has ensued as a consequence of the lack of an energy program? What is going to be the economic (and other) costs associated with an inefficient allocation system which comes under a control situation? What are the potential costs associated with another embargo?

Chapter II

ENERGY PRICES AND IMPORTS*

A. The Key Decisions

The international implications of energy policy are discussed in the final chapter of this report. However, there are two important conclusions from that chapter which have a crucial bearing on domestic energy policy:

(1) *U.S. energy policy must strive to reduce our dependence on imported oil.*

(2) *It is unlikely that feasible reductions in U.S. imports will undermine the OPEC cartel in this decade at least. Therefore, it is unwise for the United States to take undue risk with its own economy in order to achieve short-run reductions in imports.*

The first conclusion suggests policies that eventually lead to increased prices. The second conclusion implies that these increases should be gradually phased in over a period of years. The important decision is then the permissible rate of price increase. The specific decisions are:

(1) THE RATE AT WHICH "OLD" OIL IS REFINED AS "NEW" OIL.—Approximately two-thirds of domestically produced oil is now sold at the controlled price of $5.25 per barrel. The current definition of "old" oil is the 1972 production rate from the property in question less "released" oil which is production in excess of the 1972 level. This definition ignores the natural decline of oil fields and discourages secondary production. Redefinition would recognize this geological fact. The Task Force heard recommendations ranging from 1 to 4 percent per month (2 to 8 years "decontrol").

(2) THE PRICE CEILING ON "NEW" OIL.—Unless the price of new oil is controlled U.S. prices will follow OPEC price increases. The range at issue is from $7.50 in the House bill (H.R. 7104) to $11.50 in the President's proposal.

(3) SPECIAL PRICES OR EXCLUSIONS FROM THE PRICE CEILING.—The House bill would set a higher ceiling ($10.00–$11.50) for certain oil from high cost production. Others propose excluding oil recovered by secondary or tertiary methods or produced from shale or coal from controls altogether. Similar exclusions have been proposed for high cost natural gas.

(4) WINDFALL PROFITS TAX.—A windfall profits tax could be used to either (a) reduce profits from decontrol or (b) insure that profits are reinvested in energy development by introducing plowback arrangements.

(5) EXISTING CONTRACTS FOR NATURAL GAS.—Much natural gas, expecially in the interstate market, is sold under long-term contract.

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* For limitations in the analysis, see pages 7–9, Chapter I.

The effect of whatever is done with new natural gas prices will depend on what happens to the natural gas under these old contracts. Without special arrangements renegotiation is likely in the face of a natural gas shortage and the wide price differential (300 percent or more) likely between "old" and "new" natural gas.

(6) New natural gas prices.—There are four alternatives with regard to natural gas that is either newly found or released as old contracts expire.

(a) decontrol of all new natural gas;

(b) continue decontrol for gas sold in intrastate markets and control for gas sold in interstate markets with some administrative means of allocation between the markets;

(c) eliminate market distinction and set natural gas prices equal to the Btu equivalent of oil prices, either the blend price of domestically produced oil or of all oil including imports or of "new" oil; and

(d) eliminate market distinction and set natural gas prices equal to some "fair" price.

These six decisions will reflect the policy answers to the tradeoff between goals for energy and those for inflation. Higher prices provide greater cash flow to producers and greater incentives for production. Higher prices encourage conservation. Gradualism gives more weight to the inflation goal. The rate of redefinition of "old" oil and natural gas (via contract renegotiation) provides additional cash flow but little further incentive to find new oil or natural gas. Because oil and natural gas are frequently found together the price of both products influence the expected rate of return from successful wells.

Section B presents estimates of the rate of return that will follow from alternative prices for new oil and natural gas.

Section C of this chapter presents estimates of the price path for fossil fuels under alternative energy policies, including immediate decontrol. These estimates are then converted into additions to the general inflation in Section D. Estimates of the impact of these energy price paths on overall economic activity are left to chapter III.

B. The Appropriate Price for New Oil

A balance must be struck between the undesirable macroeconomic consequences of high oil prices on the one hand and the desirable stimulus higher prices provide for increasing production and encouraging conservation on the other hand. The macroeconomic impacts are discussed in Chapter III. In this section we consider the relationship between domestic oil prices and the exploration and development of new reserves.

RECENT STUDY

A recently published study by La Rue, Moore and Schafer, a petroleum consulting firm, claims to show that a price of $12.84 per barrel would have been necessary in 1974 in order to justify the exploration and drilling that took place in that year. The study calls this the economic cost of bringing in new oil where economic cost is defined as the "cost of finding and developing, and producing crude petroleum in the lower 48 States plus the minimum return on the operator's capital

necessary to sustain exploration." The presumption of the study is that it is unprofitable to search for oil in the lower 48 States if the price is less than $12.84 per barrel. Despite some limitations, the study provides a convenient departure for considering the price of oil that is necessary to encourage further exploration.

PRICE COMPUTED

The study computes the $12.84 price as follows: (1) The actual investment cost incurred in 1974 is taken as given; (2) Actual discoveries in 1974 are also taken as given and are assumed to have resulted from the investment cost just noted; (3) A pattern of production from these new reserves is assumed which extends 27 years into the future; (4) This future production is assumed to be sold at a constant price, and the receipts are discounted at a 15 percent rate of interest; (5) A price is found which makes the discounted stream exactly equal to their initial investment costs. This price is called the economic cost of producing new oil.

CASH FLOW METHODOLOGY

The discounted cash flow methodology that has just been described is the appropriate one for investment decisions that must be made by firms. One could question the usefulness of the technique for making national policy decisions about the price of oil, however, since it does not tell anything about the responsiveness of the industry to changes in the price. How much exploration would take place if oil were to be priced at $12.00 per barrel remains unknown; likewise how much more if the price were a dollar higher? In this regard it is interesting to ask why firms invested so much in 1974 when the price of oil was below $12.84 per barrel. The cash flow methodology does not answer such questions. Nonetheless, it is interesting to ask what price would be consistent in the long run with the level, the cost, and the success of exploration and drilling activity that took place in 1974. It is the determination of this price that we consider next.

ADJUSTMENTS TO COMPUTATIONS

Four adjustments will be made to the La Rue, Moore and Schafer (LMS) computations. The adjustments and their effect on the computed economic cost of new oil can be summarized as follows:

(1) LMS assume the price of natural gas will remain at $0.449/mcf over the next 28 years. If instead, a price of $1.30/mcf is assumed and the relationship of oil to gas discoveries is maintained, the extra revenue earned from gas permits a reduction in the price of oil to $11.65 without affecting the profits of oil producers.

(2) The actual outlays for lease acquisitions in 1972 are used as an estimate of the costs of the leases on which drilling occurred in 1974. However, 1972 seems to be a year of higher than average purchases of leases. If a 4 year average of lease costs is used instead, lease costs fall by 36 percent and an oil price of $10.83 is sufficient to yield the 15 percent return required in the LMS study. This price also assumes a price for gas of $1.30/mcf.

(3) The 15 percent rate of return is computed under the assumption that the price and cost of producing oil will remain constant for the next 28 years. If, instead, both the price of oil and the cost of producing it rises at an average rate of 6 percent per year, the rate of return that can be expected will be 6 percent higher than the rate required by LMS. Lowering this 21 percent rate of return to 15 percent, the price of oil that is computed by using the LMS methodology is $8.93, including the adjustments for lease costs and gas prices.

(4) This number is appropriate for mid 1974. Investment costs may have increased from 10 to 20 percent since then. At these two rates, the equivalent price of oil for mid-1975 becomes $9.59 and $10.63 per barrel respectively. Lower rates of return yield lower prices of course.

Corrections to the La Rue, Moore and Schafer Computations

Table 26 of the LMS study lists the data of interest for the year 1974. A copy of that table has been appended to this report.[1] There are eight numbers on the table that will be used here; they have been highlighted by arrows in the appendix.

The Price of Natural Gas

The first assumption we will vary is the price of natural gas. Since gas and oil are frequently discovered together and developed through the same drilling procedure, a higher price for gas will make it more profitable to look for oil. LMS assume that the price of gas will be $0.449/mcf; we will use a price of $1.30/mcf which assumes some changes in current natural gas policy. As is shown in table I, this increases the revenue derived from gas by $1,426 million. Gross revenue can be held constant only if the revenue from oil falls by the same amount, and as the table shows, this will happen if the price of oil is set at $11.65 per barrel rather than at $12.84 per barrel.

Table I.—*The effect of the price of natural gas on the price of oil if gross sales are held constant*

Price×Quantity [1]	Revenue [2]	Price×Quantity [1]	Revenue [2]
Gas: $0.449/mcf×1,675=--	$752	$1.30/mcf×1,675=-------	$2, 178
Oil: $12.84/bbl×1,195=---	15, 342	$11.645/bbl×1,195=-----	13, 916
Total (gross sales)---	16, 094	------------------------	16, 094

[1] Gas quantities are expressed in billions of cubic feet; oil quantities are in millions of barrels.

[2] Revenue figures are expressed in millions of 1974 dollars.

Lease Costs

A second simple adjustment concerns the appropriate treatment of lease acquisition costs. If the price of oil is raised substantially, lease costs will rise. The higher lease costs should not then be used as evidence that a further price increase is needed.

[1] See table, p. 62.

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LEASE COSTS ESTIMATED

How much of the lease costs should be ignored because they are price determined rather than vice versa? We don't know. We feel certain that these costs would fall if the price of oil is reduced, but we don't know by how much. Therefore, no correction was made on these grounds.

LMS uses the base expenditures of 1972 as an estimate of the costs of the leases, but 1972 happens to be a year of large lease acquisition expenditures. During 1974 drilling activity was about 25 percent greater than that in 1973, yet lease costs were three times higher. If these higher costs are due to price increases, they should be ignored because of the argument made above concerning the dependence of lease prices on oil price. If the higher costs are due to the fact that an abnormally large number of acres was leased in 1972, the estimate should be reduced.

To get an estimate of the normal level of lease costs, we averaged the lease acquisition expenditures made in 1972 with that of the preceding 3 years. Averaging reduced expenditures by 36 percent, and reduced total investment costs by 7.2 percent. With investment costs down by that percentage, adjusted gross income (AGI) can be down by that percentage as well without affecting the 15 percent profit rate calculated by LMS. The reduction in AGI is transformed in Table II to a reduction in gross sales using the proportional royalty rate and sales and ad valorem tax rates found in LMS Table 26.

TABLE II.—*Conversion of changes in adjusted gross income into changes of gross sales*

[Dollar amounts in millions]

	With all lease costs	Less 36 percent of lease costs	Percent difference
AGI	$11, 104	$10, 301	7. 3
Ad valorem and State sales taxes	863	811	6. 1
Royalty expenses	2, 012	1, 890	6. 1
Operating expenses	2, 115	2, 115	0
Total gross sales	16, 094	15, 116	6. 1

If the price of gas is kept constant at $1.30/mcf, the entire reduction in gross sales permits a reduction in oil revenues as is shown in table III.

TABLE III

[In millions of dollars]

	With all lease costs	Less 36 percent lease costs
Sales of gas	$2, 178	$2, 178
Sales of oil	13, 916	12, 938
Total	16, 094	15, 116

With sales of oil of 1,195 million barrels, revenues of $12,938 million will be obtained at a price of $10.83 per barrel.

Rates of Return

The La Rue study does not permit price to grow over time. With prices and costs held constant, the calculation yields a "real" rate of return, or a rate of return net of inflation. If one allows for a predicted rate of inflation in the price of oil of about 6-percent per year, the real rate of return of 15 percent implies the existence of a nominal rate of return of 21 percent. This is quite high. Unfortunately the rate of return enters into the calculation in a nonlinear fashion and it is awkward to check the sensitivity of the price of oil reported to different rates of return. However, the following formula should provide a good approximation to the exact adjustment that would be implied by using different rates of return. For any given price, the value of the receipts should vary with the rate of return (r) according to the following formula.

$$\text{Value of receipts} = \frac{1 - e^{-27.58(.125+r)}}{.125+r}$$

This formula is the solution to the integral which discounts future profits at rate r under the assumption that production will continue for 27.85 years and that each year's production will be 12.5 percent smaller than the previous year's. The LMS study did not use a constant decline rate, but the variable rate they did use is best approximated by a decline rate of 12.5 percent. Using this formula, we get the following values for various rates of return.

r	Formula value	3.63452 as a percent of the formula value [1]
0.09	4. 63879	78. 35
0.10	4. 43547	81. 94
0.11	4. 24880	85. 54
0.12	4. 07689	89. 15
0.13	3. 91811	92. 76
0.14	3. 77106	96. 38
0.15	3. 63452	100. 00

[1] Column 3 shows Adjusted Gross Income as a percent of the Adjusted Gross Income needed to yield a return of 15 percent.

The formula tells us the value of the future profits for each dollar of present profits earned. We are only interested in comparative values here. Thus the table tells us that if a rate of return of 10 percent is required instead of 15, that profits can be smaller by 18.06 percent. That is, 3.63452/4.3547 equals .8194. This tells us that the receipts are worth only 82 percent as much if discounted at a rate of 15 percent as they are worth if discounted at a rate of 10 percent. Alternatively, if it is felt that a 10 percent rate of return is appropriate, AGI need be only 80.94 percent as large as it would have to be if a profit rate of 15 percent were demanded. Since these are real rates of return, the 10 percent rate just noted is approximately equal to a 15 percent rate in money terms. The following table shows the effect of the rate of return on the economic cost of oil as calculated by LMS.

TABLE IV.—*The effect of the required rate of return on the price of oil*

Rate of return	0.9	0.10	0.11	0.12	0.13	0.14	0.15
AGI	$8, 071	$8, 441	$8, 812	$9, 183	$9, 555	$9, 928	$10, 301
Operating expenses	2, 115	2, 115	2, 115	2, 115	2, 115	2, 115	2, 115
Royalties	1, 550	1, 606	1, 662	1, 720	1, 776	1, 832	1, 890
Sales and A.V. taxes	665	689	714	738	762	786	811
Gross sales	12, 401	12, 851	13, 303	13, 756	14, 208	14, 662	15, 116
Gas sales	−2, 178	−2, 178	−2, 178	−2, 178	−2, 178	−2, 178	−2, 178
Oil sales	10, 223	10, 673	11, 125	11, 578	12, 030	12, 484	12, 938
Oil price	8. 55	8. 93	9. 31	9. 69	10. 07	10. 45	10. 83

Cost Increases

These prices are calculated using 1974 data and are appropriate estimates of the cost of oil at that date. To correct for inflation, several adjustments should be made. First, since oil prices are expected to grow by at least 6 percent per year, it is appropriate to convert these real rates of return into nominal rates by adding 6 percentage points. Thus the price of $8.93 per barrel in 1974 corresponds with a 16-percent rate of return.

INCREASES IN DRILLING COSTS

But costs, too, have probably changed since 1974. The cost data being used already reflect the dramatic increase in drilling costs that took place between 1973 and 1974. Cost per well is assumed to be 27-percent higher in 1974 than in 1973, and some components increased by over 50 percent.

Some of these increases represent a runup in equipment rental prices due to the temporary shortages that appeared in 1974. These prices should fall in the future. Others represent permanent increases. Since we have no way of telling how the 1975 costs will compare to the 1974 figure—data for 1975 are incomplete—we have done the calculations twice, once that costs have increased by 10 percent, and a second time assuming 20 percent. This means that sales must go up by 10 percent (or 20 percent) to maintain the same rates of return. (Since operating expenses are increased at this rate also, the distinction between AGI and Sales need not be made in this calculation.) Holding gas prices constant, the oil prices must go up by more than the rate

Table V.—*The Economic Cost of New Oil as Calculated by the La Rue, Moore and Schafer Method*

A. The price of oil per barrel if drilling costs are 10 percent higher than in 1974:

Nominal rate of return	Gas price per thousand cubic feet		
	$1.00	$1.30	$1.80
7 percent	6.77	6.35	5.65
9 percent	7.56	7.14	6.44
11 percent	8.37	7.95	7.25
13 percent	9.19	8.77	8.07
15 percent	10.01	9.59	8.89
17 percent	10.84	10.42	9.72
19 percent	11.68	11.26	10.56
21 percent	12.51	12.09	11.39

B. The price of oil per barrel if drilling costs are 20 percent higher than in 1974:

7 percent	7.52	7.10	6.39
9 percent	8.38	7.96	7.26
11 percent	9.26	8.84	8.14
13 percent	10.15	9.73	9.03
15 percent	11.05	10.63	9.93
17 percent	11.96	11.54	10.84
19 percent	12.87	12.45	11.75
21 percent	13.78	13.36	12.66

of drilling cost increases. Table V shows the 1975 oil prices that correspond to the different nominal rates of return for three different assumptions about the future price of natural gas.

How does one choose a rate of return? The question is awkward. Adelman, in his definitive study of the petroleum industry, *The World Petroleum Market* (Resources for the Future, Johns Hopkins Press, Baltimore, 1972) cites various rates of return as appropriate for the exploration and production of oil in the mid-1960's. He concludes: "The limits set in this fashion are between 5 and 13 percent; we will use 9 percent as the midpoint." Among the references he cites is a speech by J. R. Wilson, a vice-president of Shell Oil. "We have chosen 9 percent as representing a reasonable rate of return we like to expect on future invested capital for the exploration and production business." If 9 percent was appropriate for the mid-1960's, what rate is appropriate in the mid-1970's? Since the mid-1960's, two factors have raised interest rates around the world, inflation and tight money. The rates Adelman was referring to are nominal, but the time period was one in which inflation rates were very low and the distinction between nominal and real rates was not often made. To adjust these rates to levels appropriate to the mid-1970's, one must add four to six points for the difference in inflation rates and tight money. Thus using a 13 percent rate of return the oil price for the mid-1970's lies between \$8.07 and \$9.73 per barrel if the price of natural gas lies between \$1.30 and \$1.80 per Mcf. Using the 15 percent chosen by LMS the oil price for the mid-1970's lies between \$8.89 and \$10.63 per barrel if the price of natural gas lies between \$1.30 and \$1.80 per Mcf.[2]

RULES OF THUMB

From the tables, a few rough rules of thumb emerge that can be used when considering the effect of the different assumptions on the price of oil.

(1) Every extra 10 cents per Mcf of natural gas can be transformed into a 14 cents reduction in the price of a barrel of oil.

(2) Every extra percentage point that is assumed for the appropriate rate of return for drilling and exploration adds 42 cents to the price of a barrel of oil.

C. Alternative Energy Policies and the Price of Fossil Fuels

Tables IX through XII below present estimates of the prices of fossil fuel energy under various energy policy alternatives. Four prices are shown:

(1) the *price per barrel of new domestic oil;*

(2) the *average price per barrel of all oil including imports;*

(3) the *average price per thousand cubic feet* (*Mcf*) *of natural gas;* and

(4) the *average price of fossil fuel energy* (oil, natural gas, coal and natural gas liquids) in oil barrel equivalents.

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[2] The marginal relationship between the price of oil and the rate of return shown in table V is virtually the same as that shown in the Joint Economic Committee study, *Oil Profits Prices and Capital Requirements* (September 26, 1975, footnote 1, p. 14.) The average relationship differs substantially, however, since the present study is concerned with the rate of return on new investment only, while the JEC study computes the rate of return on all past equity investment, as a group. It should be noted that the two studies use very different methods to arrive at the same conclusion concerning the marginal impact of changes in the price of oil on the rate of return to investment.

The tables also show the total annual payments by all consumers for fossil fuel energy.

Table VI provides a benchmark against which alternative energy policies can be compared. The table shows estimates for the third quarter, 1975 of the four prices and consumer payments.

TABLE VI.—*Energy prices (with tariff and before OPEC increase)*

	1975:3
New oil price	$12.00/barrel.
Blend price all oil	$10.50/barrel.
Blend price natural gas	$.62/mcf.
Blend price all fossil fuel	$7.00/barrel in oil equivalents.
Consumer payments, all fossil fuel	$82 billion per annum.

The estimates in Table VI are based on the production and price estimates shown below.

TABLE VII.—*Fossil fuel production and prices for 1975:3*

(Annual Rates)

Controlled domestic oil	1.90 billion barrels at $5.25/barrel.
Uncontrolled domestic oil	1.17 billion barrels at $12.00/barrel.
Oil imports, crude and product	2.25 billion barrels at $14.00/barrel.
Interstate natural gas	13.0 tcf [1] at $.33/mcf.
Intrastate natural gas	8.0 tcf at $1.05/mcf.
Natural gas liquids	0.6 billion barrels at $4.00/barrel.
Coal	610 million tons at $20/ton.

[1] Trillion cubic feet.

BASIC METHODOLOGY

The projections for fossil fuel energy price increases and the effects of the various energy policy alternatives on inflation and unemployment rates are based on an energy simulation model developed by the Senate Budget Committee Staff.

The model includes a 3 percent annual rate of decline of production from the lower 48 States. Alaskan production begins in 1978 and increases to an average of 2 million barrels per day by the fourth quarter 1980.

"NEW" OIL AND GAS PRICES DETERMINED

The crude oil import price is equal to the OPEC price plus the import tariff (though for the cases presented in this report, the tariffs on imported crude and product have been removed). The domestic "new" oil price and the prices of intra- and interstate gas are determined as follows: for the immediate decontrol alternative, the price of oil is assumed to follow closely the OPEC price less a 50 cents per barrel quality differential. For the other alternatives, the price paths are specified. Each is explained in this chapter. Gas prices are also explained in each policy alternative. Under the phased-in alternatives, the gas prices tend to the blend price of oil (in Btu equivalence)

after their specified phasing periods end. Coal is pegged to the blend price of oil.

There is a built-in contract turnover rate for natural gas and coal following the assumption that sanctity of contract will prohibit immediate price increases when unregulated or regulated prices exceed the contract prices. The turnover rate is assumed to be described by an exponential form representing the diversity in the length of contract. In the immediate decontrol and 39-month phaseout alternatives, about two-thirds of the natural gas currently under contract is assumed to move up to the new price by the fourth quarter of 1977. In both of the 66-month phaseout alternatives, the same turnover rate is assumed for intrastate natural gas, but only about half of interstate gas is assumed to move up to the new price over the same period. The slower turnover in the latter alternatives reflects the continuation of the Federal Power Commission's (FPC) control over existing contracts. Coal contracts also involve a turnover rate similar to gas contracts not under FPC control.

CONSUMER PAYMENTS

In order to determine consumer payments, increases in raw fuel prices are passed on to final buyers on a straight dollar-for-dollar basis with no percentage markup. This is done gradually over a period of 1 year.

In the model real growth in GNP, price elasticities of supply and demand and their effects on consumption and production of fossil fuels have been held constant. Obviously, one cannot make projections of prices and quantities without such considerations. Consequently, calculations were made subsequent to running the model to make the necessary adjustments.

OPEC Price Increases

In order to compare energy policies, it is necessary to make some consistent assumption regarding OPEC price increases in 1975 and in subsequent years. The calculations in this chapter assume a $1.00 per barrel OPEC increase annually beginning in the fourth quarter 1975. Such increases would reflect the successful implementation of an OPEC policy designed to maintain a constant real oil price given a 5 to 7 percent rate of inflation in the industrial countries.

Domestic Production

In each alternative the price for new oil determines the rate of domestic production. In the $7.50 to $9.00 per barrel range, supply elasticities are relatively high; each increment in price brings forth significant increases in the rate of domestic production over a period of several years. Beyond $9.00 per barrel, supply elasticities decline rapidly. Consequently, the rate of domestic production is not substantially increased with higher prices. Because of the different rates of domestic production, the level of imports varies under each alternative.[3] Import levels increase in the near term, 1975:3 to 1977:4,

[3] Import levels also reflect the effect of energy price changes on total consumption.

under all alternatives. But by 1980:4 the effect of higher prices on domestic production has brought import levels down toward or below current levels except under the 66-month phaseout with $7.50 oil.

TABLE VIII.—*Import levels under alternative decontrol policies (MMBD)*

	Decontrol policy options			
	Immediate	39-month $11.50 oil $1.80 gas	66-month $9.00 oil $1.30 gas	66-month $7.50 oil $1.00 gas
75:3	6.2	6.2	6.2	6.2
76:4	6.6	7.0	7.2	7.3
77:4	7.3	7.7	7.9	8.6
80:4	5.2	5.2	7.0	9.4

IMMEDIATE DECONTROL

The immediate decontrol alternative assumes that price regulations on oil and natural gas prices are ended in 1975:4. The tariff on imported oil is removed. Table IX shows the effect this alternative would have on energy prices.

TABLE IX.—*Immediate decontrol (without tariff)*

	75:3	76:4	77:4	78:4	79:4	80:4
New oil price (per barrel)	$12.00	$13.00	$14.00	$15.00	$16.00	$17.00
Blend price: All oil (per barrel)	10.45	13.20	13.90	15.20	16.20	17.20
Blend price: Natural gas (per thousand cubic feet)	.62	1.40	1.90	2.25	2.55	2.80
Blend price: All fossil fuels (per oil barrel equivalents)	7.00	9.50	11.50	13.50	14.75	15.75
Consumer payments: All fossil fuels (billions, annual rates)	82	119	147	171	193	213

39-MONTH PHASE OUT

The second alternative is the oil decontrol plan proposed by the administration on July 25, 1975, coupled with the immediate decontrol of natural gas. More specifically:

(1) Old oil is decontrolled over 39 months at a rate of 1½ percent (78,000 barrels) per month for the first 12 months, 2½ percent (130,000 barrels) per month for the next 12 months and 3½ percent (182,000 barrels) per month for the remaining 15 months.

(2) The price of new domestically produced oil is set initially at $11.50 per barrel and is allowed to rise 5 cents per month to $13.45 at the end of the 39 months. For the period beyond 39 months, the price moves toward the import price.

(3) The price of natural gas is immediately decontrolled beginning in the fourth quarter 1975.

Table X presents estimates for this alternative. The estimates assume that at the end of the 39-month decontrol period, the new oil price would be uncontrolled.

TABLE X.—*39-month phaseout (without tariff)*

	75:3	76:4	77:4	78:4	79:4	80:4
New oil price (per barrel)	$12.00	$12.25	$12.85	$13.45	$16.00	$17.00
Blend price: All oil (per barrel)	10.45	11.05	12.60	14.35	16.20	17.20
Blend price: Natural gas (per thousand cubic feet)	.62	1.25	1.70	2.10	2.55	2.80
Blend price: All fossil fuels (per oil barrel equivalents)	7.00	8.00	9.94	11.81	14.41	15.72
Consumer payments: All fossil fuels (billions, annual rates)	82	100	127	154	192	213

66-MONTH PHASEOUT, $9.00 OIL AND $1.30 NATURAL GAS

This alternative has four basic provisions:

(1) *Decontrol of "old" oil over 66 months* with 1½ percent of the initial quantity of old oil redefined as new oil each month beginning in September 1975.

(2) *A price ceiling on "new" domestically produced oil set initially at $9.00 per barrel* and rising by 5 cents each month to $12.30 at the end of the 66-month period.

(3) *Extension of natural gas controls to the intrastate market* with the ceiling price of new natural gas set initially at $1.30 per Mcf and increasing at 1 cent per month for 66 months.

(4) *Removal of the tariff* on imported oil.

ESTIMATES OF PRICES

Estimates of the prices of fossil fuels and payments which would result from this alternative are shown in table XI. It should be noted

TABLE XI.—*66-month phaseout, $9.00 oil, $1.30 gas (without tariff)*

	75:3	76:4	77:4	78:4	79:4	80:4
New oil price (per barrel)	$12.00	$9.75	$10.35	$10.95	$11.55	$12.15
Blend price: All oil (per barrel)	10.45	10.30	11.40	12.35	13.35	14.35
Blend price: Natural gas (per thousand cubic feet)	.62	.90	1.10	1.30	1.50	1.65
Blend price: All fossil fuels (per oil barrel equivalents)	7.00	7.25	8.25	9.00	10.25	11.25
Consumer payments: All fossil fuels (billions, annual rates)	82	86	107	119	135	153

that at the end of 1980:4, the oil prices assumed are $17.50 for the 39-month alternative, and $12.30 for the 66-month $9.00 alternative. In addition, the end of the 66-month period occurs at the beginning of 1981:2, in the second quarter beyond the analysis. No assumptions are made as to any price increases in the 67th month or any impact anticipating such increases in the pattern of domestic production or imports.

66-MONTH PHASEOUT, $7.50 OIL AND $1.00 NATURAL GAS

This alternative differs from the preceding alternative in that the initial prices of new oil and natural gas set at $7.50 and $1.00 respectively.

Estimates of the prices of fossil fuels and payments which would result from this alternative are shown in table XII.

TABLE XII.—*66-month phaseout, $7.50 oil, $1.00 gas (without tariff)*

	75:3	76:4	77:4	78:4	79:4	80:4
New oil price (per barrel)	$12.00	$8.25	$8.85	$9.45	$10.05	$10.65
Blend price: All oil (per barrel)	10.45	10.00	11.15	12.30	13.35	14.45
Blend price: Natural gas (per thousand cubic feet)	.62	.75	.90	1.10	1.25	1.40
Blend price: All fossil fuels (per oil barrel equivalents)	7.00	6.75	7.75	8.25	9.25	10.25
Consumer payments: All fossil fuels (billions, annual rates)	82	85	100	108	123	139

D. Inflationary Effects

The increase in the general price level associated with each energy policy alternative is approximated by relating the increases in the payments made for fossil fuel energy to the GNP. Increases in payments for energy for each of the alternatives are shown in table XIII.

TABLE XIII.—*Increases in fossil fuel energy payments*

[In billions of dollars]

	1975:3–1975:4	1976:4–1977:4
Immediate decontrol	37	28
39-month phaseout	18	27
66-month phaseout $9, $1.30	4	21
66-month $7.50, $1	3	15

The direct effects of increases in energy payments on the price level are shown in table XIV.

TABLE XIV.—*Increase in general price level, direct effect only*

[In percent]

	1975:3–1976:4	1976:4–1977:4
Immediate decontrol	1.9	1.2
39-month phaseout	.8	1.1
66-month phaseout $9, $1.30	0	.8
66-month, $7.50, $1	−.1	.5

These preceding estimates show only the initial increase in the price level (the impact effect) from an energy shock. They are not a full account of price developments because the calculations allow no feedback from higher prices to higher wages and in turn to still higher prices. In the next chapter the Wharton Econometric Model is used to estimate these feedback effects as well as to examine the unemployment consequences of an energy shock.

APPENDIX

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COST OF NEW OIL
RESERVES ADDED IN 1974
TOTAL UNITED STATES

TIME YEARS	(1) GROSS OIL PRODUCTION THOUSANDS OF BBLS	(2) GROSS GAS PRODUCTION MILLIONS OF CU-FT	(3) GROSS OIL & GAS SALES THOUSANDS OF $	(4) ROYALTY EXPENSE THOUSANDS OF $	(5) ADVALOREM & STATE TAXES THOUSANDS OF $	(6) OPERATING EXPENSES THOUSANDS OF $	(7) ADJUSTED GROSS INCOME THOUSANDS OF $	(8) TOTAL INVESTED CAPITAL THOUSANDS OF $
1974	40962	57429	551667	68958	29590	39042	414076	4491000
1975	81924	114857	1103334	137917	59180	78084	828153	0
1976	81924	114858	1103333	137917	59180	78084	828153	0
1977	81924	114857	1103334	137917	59180	78084	828153	0
1978	81924	114858	1103334	137916	59180	78084	828153	0
1979	81924	114857	1103333	137917	59180	78084	828153	141000
1980	81924	114857	1103334	137917	59180	78084	828153	0
1981	80720	113169	1087115	135889	58311	78084	814831	0
1982	72706	101935	979191	122399	52521	78084	726187	0
1983	64487	90410	868495	108562	46584	78084	635266	0
1984	57197	80190	770314	96289	41318	78084	554623	0
1985	50731	71125	683232	85404	36646	78084	483097	0
1986	44995	63084	605994	75749	32504	78084	419656	0
1987	39910	55953	537487	67186	28830	78084	363388	0
1988	35397	49627	476725	59591	25570	78084	313481	0
1989	31396	44017	422833	52854	22680	78084	269215	0
1990	27847	39041	375032	46879	20116	78084	229953	0
1991	24698	34628	332636	41579	17841	78084	195131	0
1992	21907	30712	295032	36879	15825	78084	164244	0
1993	19430	27241	261679	32710	14036	78084	136849	0
SUB-TOTAL	1103927	1547705	14867433	1858429	797452	1522638	10688914	4632000
REMAINING 7.58 YRS	91073	127685	1226555	153320	65789	592222	415224	0
TOTAL	1195000	1675390	16093988	2011749	863241	2114860	11104138	4632000

TIME YEARS	(9) INTANGIBLE DRILLING COSTS THOUSANDS OF $	(10) DEPLETION ALLOWANCE THOUSANDS OF $	(11) DEPRE-CIATION THOUSANDS OF $	(12) TAXABLE INCOME THOUSANDS OF $	(13) INVEST-MENT TAX CREDITS THOUSANDS OF $	(14) FEDERAL INCOME TAXES THOUSANDS OF $	(15) AFTER TAX NET INCOME THOUSANDS OF $	(16) NET CASH FLOW THOUSANDS OF $	(17) NET CASH FLOW DISC. 15% THOUSANDS OF $
1974	2634975	31056	32565	-2284518	25	-1142284	1556361	-2934638	-2736564
1975	0	199372	65129	563650	66477	215348	612804	612803	496906
1976	0	199372	65130	563652	0	281826	546327	546327	385219
1977	0	199372	65130	563651	0	281826	546328	546328	334974
1978	0	199372	65129	563651	0	281825	546327	546327	291281
1979	103635	199372	68834	456312	2615	225541	602613	461613	214013
1980	0	199372	68834	559947	0	279973	548179	548179	220997
1981	0	196442	67822	550568	0	275284	539547	539547	189146
1982	0	176939	61089	488158	0	244079	482108	482108	146964
1983	0	156937	54183	424145	0	212073	423193	423193	112178
1984	0	139196	48058	367370	0	183685	370938	370938	85502
1985	0	123460	42625	317012	0	158506	324591	324591	65059
1986	0	109503	37806	272348	0	136173	283483	283483	49409
1987	0	97123	33533	232731	0	116366	247022	247022	37438
1988	0	86145	29741	197595	0	98798	214683	214683	28293
1989	0	76405	26380	166430	0	83215	186000	186000	21316
1990	0	67769	23397	138788	0	69394	160559	160559	16000
1991	0	60107	20752	114271	0	57135	137995	137995	11958
1992	0	53312	18406	92526	0	46263	117982	117982	8890
1993	0	47285	16326	73238	0	36619	100230	100230	6567
SUB-TOTAL	2738610	2617911	910869	4421525	69118	2141645	8547269	3915270	-14454
REMAINING 7.56 YRS	0	160375	76521	178328	0	89164	326060	326060	14454
TOTAL	2738610	2778286	987390	4599853	69118	2230809	8873329	4241330	0

GROSS OIL PRICE $ 12.84 / BBL
GROSS GAS PRICE $ .449 / THOUSAND CU-FT
TOTAL RESERVE LIFE 27.58 YEARS
LEASEHOLD INVESTMENT (000) $ 906000.

ROYALTY INTEREST 12.50 %
FEDERAL INCOME TAX RATE 50.00 %
ADVALOREM AND STATE TAX RATE 6.13 %

The Response of United States Domestic Oil and Natural Gas Supply to Changing Domestic Oil and Natural Gas Prices: 1975 and Beyond

By Dr. Theodore Eck,
Chief Economist,
Standard Oil of Indiana

It is understandably difficult for the lay observer to relate higher oil prices with improved U.S. production prospects because during the past three years production has declined despite sharply higher domestic and world prices. The analytical problem presented is that prices and other consideration's relating to exploration and production (acreage availability, taxes, government policies, environmental restraints, etc.) must be compared first with activity gains and the rate of reserve additions, rather than with currently observed production rates. It is agreed that a minimum of three to five years is required before total reserve additions can respond significantly to changes in the economic environment. An actual reversal in total production rates could take considerably longer depending upon the relative depletion rate of old fields versus reserve additions.

The Shape of Petroleum Supply Curves

It is impossible to accurately describe U.S. petroleum supply response to price because prices have only recently increased to unprecedented levels. The additional supply potential at still higher prices also is undetermined. A number of years are required before there is sufficient statistical basis for determining the specific reserve additions that should be attributed to any given time period and associated activity level. We will have to wait until at least 1980 before we can be very sure about the success of the recent sharp increase in domestic exploration activity. Historical supply data combined with knowledge of present costs by area and activity, nevertheless, provide a basis for informed judgment regarding the probable shape of oil and gas supply curves. Charts 1 and 2 represent estimated long-term new supplies, or reserve additions that would be expected at various prices assuming 1975 cost conditions. (See also Table 1.)

Supply elasticity is probably somewhat less than unity in the \$5.00 to \$12.00/Bbl. range of oil prices (historic data suggest an observed 0.7 supply elasticity), but at prices of \$12.00 to \$15.00/Bbl. unit elasticity is probable. In this price range the threshold cost of oil in large potentially profitable frontier oil provinces is passed including operations in deep water, unexplored parts of Alaska on and offshore, etc. In the case of

Alaska, not only are all basic exploration and production costs very high, but new discoveries will have to bear the huge cost of another Alaskan pipeline. Similarly, the minimum entry costs of drilling in very deep waters involve high onsite well investment and large transportation costs to move barrels produced onshore. At some price above $15.00/Bbl. supply is thought to be very elastic over the long run as synthetics become economically viable.

Observed elasticities of less than one are probably due to basic increasing cost considerations. In established areas the set of geological opportunities becomes depleted with successive increments of drilling effort. Improved geophysical and drilling technology are offsetting forces but they are not generally sufficient to balance the fact that the largest and least costly discoveries normally occur fairly early in the commercial life of most areas.

Other basic trends contributing to increasing costs are deeper wells, a shift to offshore activities, operations in deeper waters, and production in the Arctic. (See Tables 2 and 3.) In an established oil province, successive efforts to boost output via in-fill drilling, producing smaller and thinner sands, added enhanced or tertiary recovery technology, etc. all ultimately involve steadily higher unit costs.

The elasticity of petroleum supply is thought to increase at prices above $12.00/Bbl. for several reasons including the fact that the threshold cost of substantial tertiary recovery technology is above this level. Higher crude oil prices also boost the upstream or exploratory portion of total investment. Within petroleum companies, exploration investment is marginal in the sense that it is postponable, risky, and often less attractive than many other basic capital spending programs. Most companies have a number of high-priority outlays such as equipment replacement, environmental conformity projects, and development drilling which have first claim to funds available. Higher prices, however, tend to provide additional internal cash flow sufficient to fund expanded exploration programs. Higher crude oil prices also increase the relative attractiveness of U.S. exploration versus overseas ventures or domestic downstream operations. Moreover,

higher prices increase the flow of external capital into the petroleum industry as well as boost internal cash availability.

Finally, higher prices may open up new frontier reserves which are not economically viable at lower prices. Much future Arctic and U.S. development probably will require prices in excess of $12.00/Bbl.

A related consideration of interest is the tendency for rates of return over the longer term to be fairly independent of exploration strategy. In part this is due to the random occurrence of giant strikes the probability of which is correlated best with the overall size of exploration programs. This is notwithstanding the fact that new giant strikes certainly occur more frequently in frontier areas, as do dry holes. In areas where geology is relatively well known, dry holes are less frequent but so are large discoveries. Small, thin reservoirs onshore that are commercial in the "Lower 48" are simply uneconomic in deep water or Arctic areas. Thus, it isn't surprising that the rate of profitability of an exploration strategy that is weighted towards looking only for giants in frontier areas hasn't been necessarily better than careful processing of acreage in more established geological provinces. This condition is explained in part by mobility of exploration and production capital between various potential petroleum provinces. The relatively small variance in the earnings performance of principal producers despite differences in exploration programs further attests to the condition of fairly constant returns to scale of effort.

Gas Supply Economics

The increasing cost conditions cited for crude oil also generally apply to gas. A major difference, however, is the normal absence of enhanced recovery opportunities. On the other hand, higher gas prices may provide a more elastic response of supply in deep water, deep formations, perhaps the Arctic, and from other high cost sources. Another principal area of price sensitivity of gas supply is in so-called tight formations where major additional fracturing is required to release reserves and/or where per well deliverability is so small as to be uneconomic at existing prices.

The historical record of gas supplies in response to price is even more deficient than in the case of oil because of the duration and severity of government controls. In addition, there are less dependable data on the cost of synthetic gas or imported LNG. As a general proposition, however, it is probable that synthetic gas will be more costly than synthetic liquids, particularly on a delivered cost basis. Part of the problem is that liquids manufacture requires less addition of costly hydrogen to generally hydrogen-deficient feedstocks, e.g., coal or shale.

In the case of LNG imports, North Africa and the Persian Gulf are the largest likely suppliers, and transportation costs would favor moving gas to Europe and Japan rather than the U.S.

Thus, the gas supply curve is probably somewhat less price elastic than the crude oil supply curve within the $1.00 to $3.00/MM BTU equivalent price range. However, given the greater relative end use value of gas and generally higher alternative supply costs, e.g., domestic SNG and imported LNG, incremental conventional supplies of natural gas have greater private and social value than heat-equivalent amounts of oil.

U.S. Exploration and Production Experience

The record of increasing cost conditions in petroleum exploration is probably best described by fitting unit costs with well depth. The relationship between water depth, climate and drilling costs is also available and described in a recent NPC study (see Tables 2 and 3, and Chart 3). It is noteworthy that offshore development costs are considerably more sensitive to physical conditions than are drilling costs.

Higher costs in the face of decreasing real oil prices lead to the observed reduction in reserve additions of crude oil in the U.S. during the past few years. Severely restrained gas prices similarly explain the very unsatisfactory rate of addition of gas reserves.

More recently both oil and gas prices have increased, though not as dramatically in the U.S. as is popularly believed when allowance is made for much higher effective tax rates and inflation. As noted in Tables 4 and 5, petroleum industry profits

on a general price inflation adjusted basis in the third quarter of 1975 were only 30 percent above the comparable 1971 level, and actually slightly lower if adjusted for the actual increase in exploration and production costs experienced. The petroleum industry has suffered the same high rates of cost escalation experienced by other industries dependent upon construction and basic engineering services.

Higher oil prices despite greater tax and cost burdens have resulted in substantial boosts in exploration spending. Not only are total budgets up more than cash flow, but real activity is up sharply as well. The fact that overall outlays are rising faster than cash flow tends to attest to the probable ultimate elasticity of new discoveries to price. For example, the leading edge of petroleum exploration, seismic activity, has now more than doubled as measured in terms of line miles above the depressed 1969-1971 level. (See Charts 5 and 6.) The number of active drilling rigs and exploratory wells drilled have also reacted impressively to the improved economic climate for exploration.

The Cash Flow Restraint

As a general proposition, the principal determinant of petroleum exploration and production activity is internally generated cash flow. Though external capital sources may appear large, in the aggregate they make only a modest relative contribution to the enormous capital spending requirements of the petroleum industry. Moreover, equity rather than debt capital normally is required to underwrite exploration activities because of the high risk associated with even the largest commitments. Discoveries of the very large reserves that make the difference between successful and unsatisfactory returns on drilling efforts in frontier areas are sufficiently erratic and unpredictable as to require that most exploration be financed with permanent capital.

In fact, the consolidated debt position of most oil companies has risen rapidly toward maximum debt/equity levels in recent years when exploration outlays declined relative to spending on transportation, refining, and marketing. With existing high debt/equity ratios and with future domestic capital spending

oriented towards exploration, even less reliance on added debt will be possible in the future.

Access to external equity has not improved despite higher oil prices and potentially improved profit prospects. (See Table 4.) The common shares of most companies sell below book value and far lower than the replacement cost of assets per share. Equity financing is generally not attractive under such market conditions. Significantly higher equity valuations probably will have to await an end of price controls, anti-trust suits, and the other political or environmental uncertainties facing the industry. These same considerations, as well as the very high outlays to finance even small exploration plays, limit the present entry of a large number of new firms into exploration activities.

Higher oil prices provide not only a larger number of exploration and drilling prospects that meet ROI requirements as dictated by the cost of risk capital, but they also supply requisite investment funds. On the average, the petroleum industry must spend between $9.00 and $10.00/Bbl. to replace the oil now being consumed. Because of the low book cost of most oil sold today which was generally discovered a decade or more ago, the after tax cash flow on the sale of a barrel of oil at the world price of $13.00 to $14.00/Bbl. is generally less than $10.00/Bbl. In other words, the industry is roughly breaking even on a cash flow basis on the sale of oil at world prices and present replacement costs. Needless to say, when barrels are sold at $5.25/Bbl., the industry can only fund a fraction of the replacement barrel investment.

A particularly difficult problem facing the petroleum industry due to its increasing cost structure is the temptation of governments to seek to control prices at some level approximating average or median costs. (See Table 5.) The estimated median cost level by definition implies that half of new oil costs lie above the average. If prices were controlled at the median cost level, roughly half of potential new oil reserves available between the domestic control prices and the prices would not be economic. Such policies result in paying far higher prices for imports than either the private or social cost of marginal domestic production. Of course a price rollback below average replacement cost as is being presently debated in the U.S.

would substantially reduce domestic exploration and increase reliance on more costly imports. It also should be emphasized that both marginal and average exploration and production costs will certainly rise rapidly in the future if any serious effort is made to equate new oil discoveries with the present rate of consumption. The increasing cost conditions inherent to the industry virtually guarantee that unit costs will escalate with any major new discovery efforts.

A troublesome issue in this regard is that future oil price increases may be expected to result in temporary advances in the book rate of return on old assets, yet overall petroleum industry cash flow deficiencies are likely to persist. At the present time most companies have more potentially profitable oil prospects with new oil prices at $14.00/Bbl. than they can finance from internal and external cash sources. These are bona fide new investment opportunities in that engineering feasibility studies have been completed and a determination made that there are no shortages of needed rigs, materials, or manpower.

In summary, the only resolution of the serious overall cash flow shortage facing the petroleum industry that appears to be a potential prospect within the not too distant future is complete decontrol of all oil prices and accelerated decontrol of gas prices. Alternatives to this action, such as substantive tax relief or direct government financing, are unlikely.

Limitations of a Two Oil Price System

The petroleum industry is unique not only as the only competitive sector of the U.S. economy subjected to price controls, but it is also the object of a curious scheme to maintain a multi-price system applied to producer sales. The alleged objective is to prevent windfall gains due to price increases, but its application ignores the generally understood supply-inducing functions of market prices. If the public wants more of virtually any commodity or service other than petroleum, all producers are rewarded whatever price is required to equate market supply and demand. If more wheat is desired, for example, the price of all wheat rises, not just volumes produced above some previously established levels.

A two price system applied to petroleum is a particularly onerous and socially costly venture because of the irreplaceability of barrels of reserves abandoned, the time required to replace volumes of oil now being consumed, the cost of imports in the interim, and the sheer magnitude of the assets misdirected.

The most visible effect of the two price system is to accelerate the rate of domestic production decline. This condition is illustrated in Charts 7 and 8. Less apparent is the shift of investment away from old oil which results in premature field abandonment, postponement of new enhanced recovery projects, fewer in-fill and workover wells, and less engineering investment to optimize the output from established reservoirs. The social cost of these dislocations can be directly measured both in the present value of higher current and prospective import requirements and in the permanent loss of domestic oil production. Such permanent losses result from well and field abandonment, failure to make required investment in pressure maintenance early enough to avoid loss of reserves, failure to in-fill drill or produce marginal sands prior to abandonment, etc.

The most serious effect of the two price system, however, is that consumers pay far less than the present replacement cost of "old oil" now being consumed and as a consequence, only a fraction of that oil is in fact being replaced. It should also be cautioned that the burden of the two price system as presently constituted in the U.S. increases more than proportionally with the duration of the program. The most noticeable manifestation of this effect is the increasing difficulty of qualifying enhanced recovery projects for "new oil" status.

The Economics of Enhanced Recovery

A discussion of evolving new enhanced recovery technology is largely academic at this point as long as most such oil produced would have to be sold at controlled prices far below either costs or world prices. No significant volumes of tertiary oil are recoverable at costs below $10.00/Bbl., and $12.00/Bbl. or more appears to be more representative of commercially viable project costs. Secondary recovery efforts have been maximized up to the

present $5.25/Bbl. control price, which has left about 40 percent of all U.S. production on primary drive only.

Future opportunities for large-scale applications of secondary recovery to old fields are restrained by most of the geological limits which apply to primary yields, though many small field development projects would be viable at higher prices. (See Tables 6 and 7.) Tertiary methods, however, can dramatically boost reservoir recovery of many large as well as small fields. It is estimated that ultimately, new enhanced recovery projects could boost production 4.0 MMBD, or roughly equal to half of the present total U.S. oil output. In fact, this well could be a conservative estimate because it is based on an assessment of present technology and often sketchy knowledge of reservoir conditions. The Amoco Production Company recently made a detached inventory of its own prospects for enhanced recovery. (See Table 8.) That study concluded that additional enhanced recovery potential appears greater than all of its present proved recoverable reserves. In part this optimistic assessment reflects a large relative acreage position in areas most amenable to tertiary recovery, but it also suggests that more careful analysis of industry prospects may yield more opportunities than are now generally recognized.

Synthetic Fuel Economics

Though the threshold costs of entry into synthetic production are probably in the $14.00 to $18.00/Bbl. range, it is not correct to suggest that costs will be constant to scale once technology is established. There are inherent increasing cost conditions in synthetics production, albeit at a more modest rate than applies to conventional oil and gas. In the case of shale oil, there are relatively limited supplies of high kerogen yield rocks, particularly those close to the surface. As production expands, less favorable basic yield and overburden conditions will be encountered. Water resources threaten to limit both coal and shale oil production in the West. To a yet indeterminate extent, general local political and social considerations may restrain otherwise economic development rates.

Potentially offsetting some of these cost pressures over the long term may be improved technology due to both breakthroughs and improved operating performance with existing systems. Hopefully, such cost improvements will more than offset the tendency for heavy engineering costs to rise considerably more rapidly than the average costs of other general goods and services (GNP deflator). To date, estimated synthetic fuels cost escalation has been running a close race with the increasing costs experienced in producing conventional petroleum fuels.

It remains to be seen whether or not sufficiently favorable price and cost relationships and government policies will evolve to permit synthetic fuels to make a meaningful contribution to energy supplies in the coming decade. (See NPC estimates, Charts 9 and 10.)

Table 1

KNOWN U.S. CRUDE OIL RESERVES
(Billion Barrels)

Type	Amount
Remaining Proved	40
Tertiary Potential*	110
Nonrecoverable	185
Total Oil In-Place	335

*Probable 55 recoverable

Table 2

OFFSHORE EXPLORATION
DRILLING COST INDEX*

Water Depth (Meters)	Climatic Conditions				
				Ice-Laden	
	Mild	Moderate	Severe	75%	100%
200	.8	1.0	1.8	2.3	4.6
500	1.0	1.3	2.1	2.8	5.4
1,000	2.5	2.8	3.6	4.3	6.4
4,000	3.8	4.0	4.3	5.6	7.5

*Moderate Climate at 200 meters = 1.0

Table 3

RELATIVE OFFSHORE DEVELOPMENT AND PRODUCTION EXPENDITURES*

Water Depth (Meters)	Climatic Conditions: Mild	Moderate	Severe	Ice-Laden 75%	Ice-Laden 100%
200	.9	1.0	2.8	Considered	
300	-	-	6.2	Substantially	
500	2.7	3.0	-	Greater	
1,000	4.3	4.8	10.2	Than Severe	

*Moderate Climate at 200 meters = 1.0

Table 4

CASH FLOW vs. INVESTMENT 20 OIL COMPANIES

	Billion Dollars 1972	1974
Cash from Operations	14.2	23.2
Borrowing and Other	1.3	2.8
Total	15.5	26.0
Investment - U.S.	6.6	13.1
- Other	4.0	6.0
- Total	10.6	19.1

Table 5

APPARENT U.S. OIL INDUSTRY PROFITS AND EFFECTS OF COST INCREASES

Basis	Third Quarter Profits Comparison 1975 vs. 1971
Unadjusted Current Dollars	+69%
Constant Dollars (GNP Deflator)	+30%
Constant Dollars (E & P Cost Index)	- 1%

Table 6

U.S. FUTURE NEW ENHANCED OIL RECOVERY (Million Barrels/Day)

Method	Amount
Thermal	1.5
Miscible (CO_2 & LP_6)	1.8
New Waterflood	.8
Total	4.1

Table 7

STAGES OF OIL RECOVERY

Primary	Secondary	Tertiary
Solution Gas Drive	Waterflooding	Miscible Flooding
10-20%*	30-50%*	60-80%*

*Range of cumulative recovery

Table 8

TOTAL AMOCO CRUDE OIL "BARRELS" (NORTH AMERICA)

	Barrels (Billions)	% Original Oil In Place
Produced	3.5	24
Proved Reserves	2.4*	16
Additional Secondary Plus Tertiary Recovery Potential	3.5	24
Considered Unrecoverable	5.3	36
Totals	14.7	100

*60% in fields under secondary recovery operations

CHART 1

Estimated Ultimate Gaseous Hydrocarbon Availability Versus Price in Constant 1975 Dollars

(Log Scales)

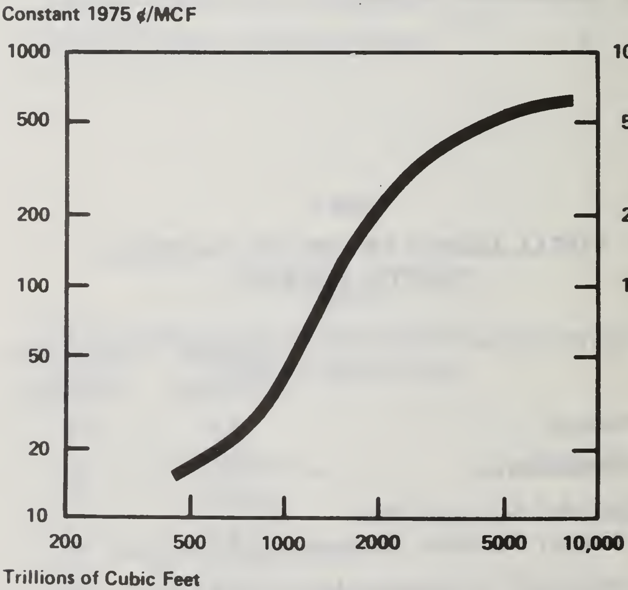


CHART 2

Estimated Ultimate Liquid Hydrocarbon Availability Versus Price in Constant 1975 Dollars

(Log Scales)

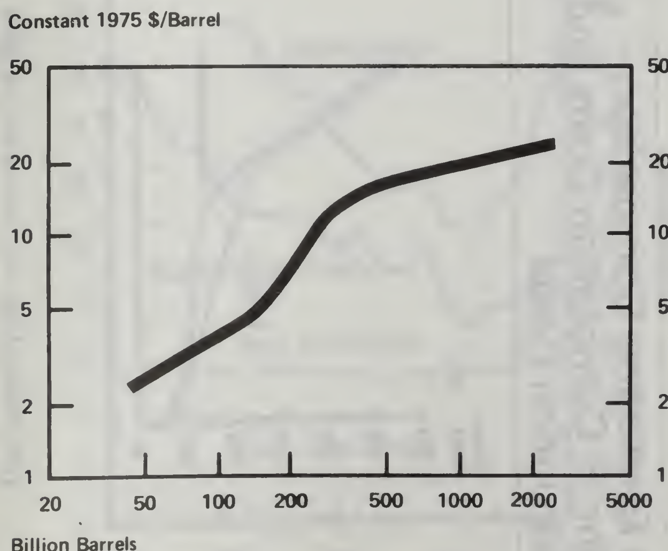


CHART 3

Cost Escalation Comparison— Drilling & Completion Costs and Process Construction Costs

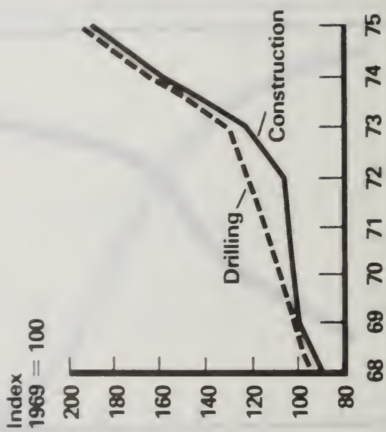


CHART 4

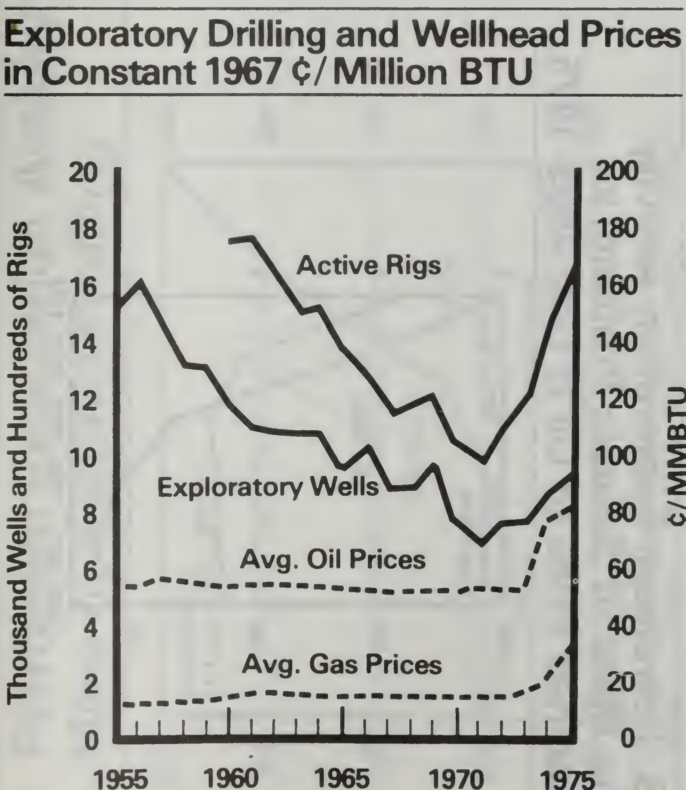

Exploratory Drilling and Wellhead Prices in Constant 1967 ¢/Million BTU
Thousand Wells and Hundreds of Rigs
¢/MMBTU
Active Rigs
Exploratory Wells
Avg. Oil Prices
Avg. Gas Prices
0
2
4
6
8
10
12
14
16
18
20
0
20
40
60
80
100
120
140
160
180
200
1955
1960
1965
1970
1975

CHART 5

U.S. Petroleum Exploration Activity (Line-Miles of Seismic Profiling) vs. Combined Price of Oil & Gas, 1969-1975.

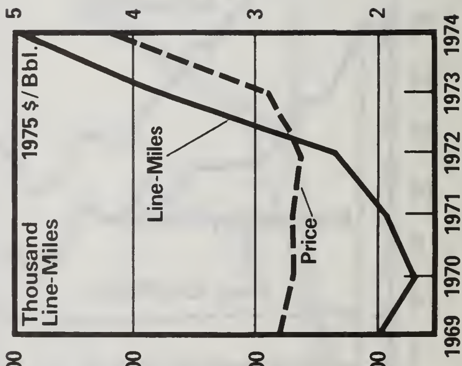


CHART 6

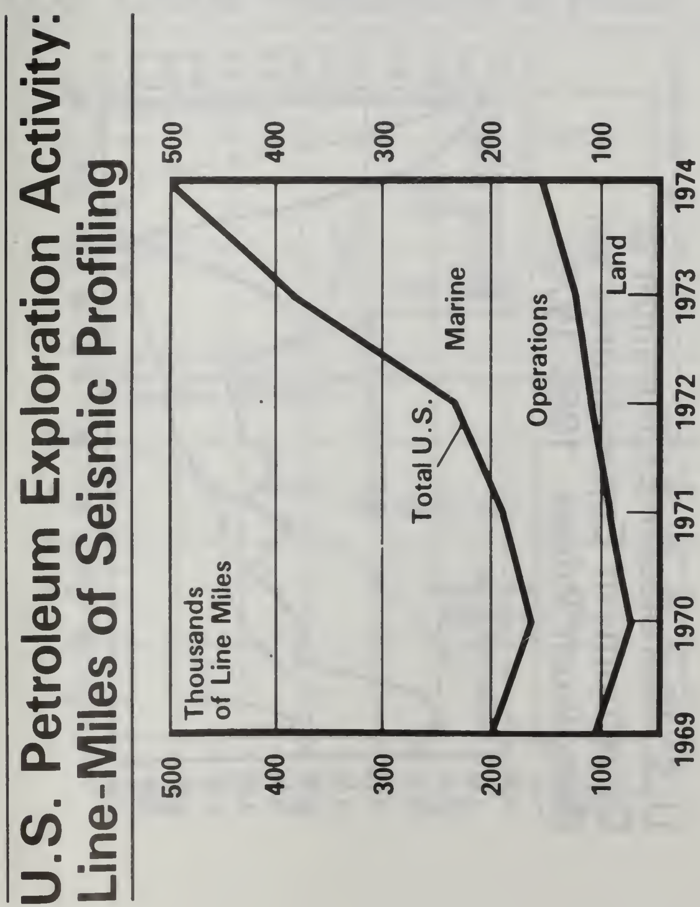
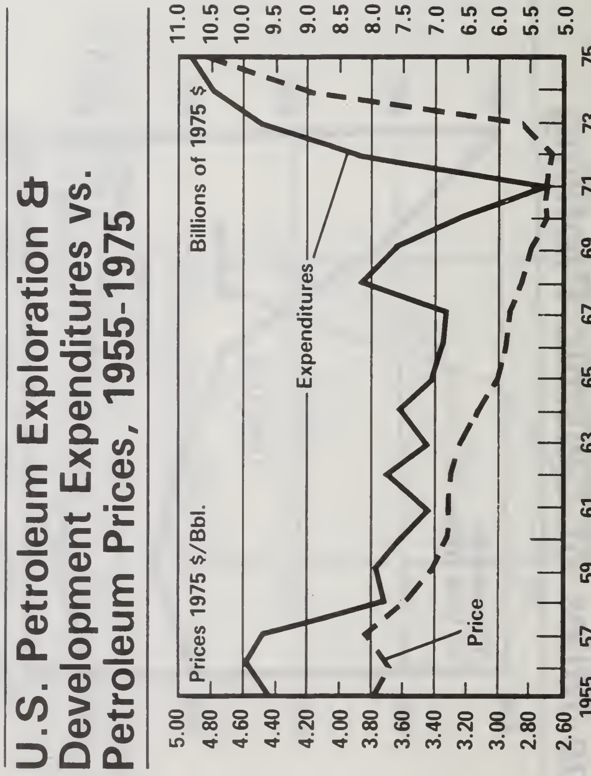

U.S. Petroleum Exploration Activity:
Line-Miles of Seismic Profiling
Thousands
of Line Miles
500
400
300
200
100
Total U.S.
Marine
Operations
Land
1969
1970
1971
1972
1973
1974

CHART 7



U.S. Petroleum Exploration & Development Expenditures vs. Petroleum Prices, 1955-1975
Prices 1975 $/Bbl.
Billions of 1975 $
Expenditures
Price
5.00
4.80
4.60
4.40
4.20
4.00
3.80
3.60
3.40
3.20
3.00
2.80
2.60
11.0
10.5
10.0
9.5
9.0
8.5
8.0
7.5
7.0
6.5
6.0
5.5
5.0
1955
57
59
61
63
65
67
69
71
73
75

CHART 8

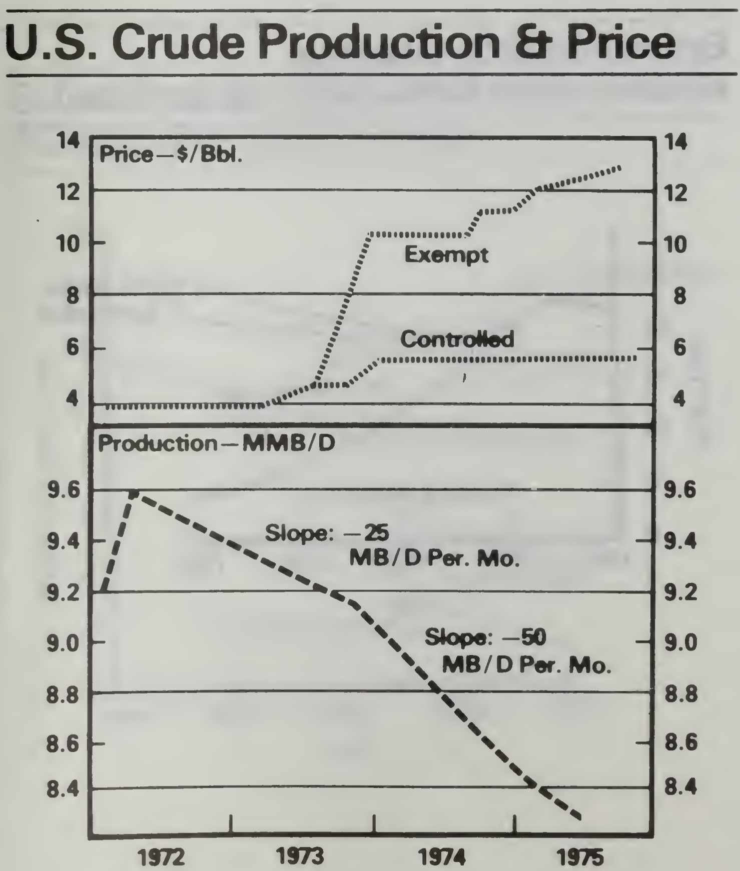

U.S. Crude Production & Price
Price—$/Bbl.
14
12
10
8
6
4
Exempt
Controlled
Production—MMB/D
9.6
9.4
9.2
9.0
8.8
8.6
8.4
Slope: —25
MB/D Per. Mo.
Slope: —50
MB/D Per. Mo.
1972
1973
1974
1975

CHART 9

Estimated U.S. Gaseous Hydrocarbon Availability (Base Case)

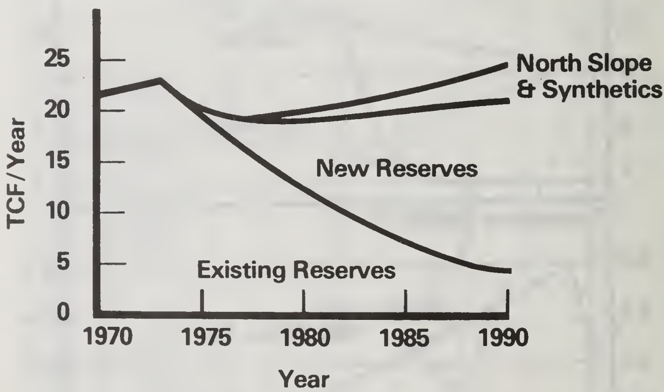


CHART 10

Estimated U.S. Liquid Hydrocarbon Availability (Base Case)